Re Louisville Gas and Electric Company
Case No. 2000-080

Kentucky Public Service Commission
September 27, 2000

ORDER establishing the revenue requirement for the gas operations of a combined electric and gas utility. Commission approves an increase in gas revenue requirement of $20.193 million, reflecting an 11.25% rate of return on equity. In determining the appropriate return on equity the commission gave consideration to the revenue stabilizing effects of a weather normalization adjustment clause approved for the utility.

The return requirement for gas operations is determined by applying the overall cost of capital to gas capitalization, rather than adjusted test period rate base. Commission finds that the capitalization of the utility is a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility. It adds that to impute operating income requirements based on an inflated rate base would, in effect, establish a cost of doing business that is non-existent to the utility. The commission would, however, determine revenue requirement based on rate base if the evidence indicated that such an approach were justified.

Generally, rates are designed to move toward fully allocated cost recovery while minimizing the rate impact for all customer classes. However, none of the authorized increase is allocated to the special contract class in light of the possibility of bypass and loss of contribution to fixed costs.

Commission reduces test-year operating expenses to reflect savings associated with a reduction in the number of employees resulting from a voluntary retirement program.

The utility is authorized to recover, over an eight-year amortization period, $1.7 million incurred to cleanup various contaminates at manufactured gas plants formerly-owned by the utility.

Commission excludes outside legal expenses from gas rates for lack of specific information concerning the nature of the expenses. Moreover, it directs the utility to cease its practice of allocating all outside legal expenses between its electric and gas operations regardless of the nature of the expenses and instead to first examine the expenses to determine if they can be directly assigned.

P.U.R. Headnote and Classification

1.

RATES

s120.1

Ky.P.S.C. 2000

[KY.] Reasonableness -- Historic test period -- Consideration of known and measurable changes -- Natural gas rate proceeding.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

2.

RETURN

s7

Ky.P.S.C. 2000

[KY.] Basis for computation -- Adjusted test-year capitalization -- Combined gas and electric utility -- Gas-only rate case.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

3.

RETURN

s92

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Basis for computation -- Adjusted test-year capitalization.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

4.

RETURN

s83

Ky.P.S.C. 2000

[KY.] Combined electric and gas utility -- Basis for computation -- Adjusted test-year capitalization -- Gas-only rate case.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

5.

APPORTIONMENT

s43

Ky.P.S.C. 2000

[KY.] Combined electric and gas utility -- Common operating expense allocation factors -- Allocation to gas operations.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

6.

VALUATION

s235

Ky.P.S.C. 2000

[KY.] Combined electric and gas utility -- Allocation of common utility plant -- Allocation to gas operations.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

7.

VALUATION

s281

Ky.P.S.C. 2000

[KY.] Combined gas and electric utility -- Total gas plant in service -- Allocation of common plant and construction work in progress.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

8.

VALUATION

s281

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Gas operations rate base -- Prepayments -- Exclusion of regulatory assessment.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

9.

VALUATION

s298

Ky.P.S.C. 2000

[KY.] Prepayments -- Exclusion of regulatory assessment -- Gas operations rate base.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

10.

VALUATION

s290

Ky.P.S.C. 2000

[KY.] Cash working capital allowance -- 45-day, or one-eighth, formula method -- Gas operations rate base.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

11.

VALUATION

s81

Ky.P.S.C. 2000

[KY.] Accumulated depreciation -- Test-period balance -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

12.

VALUATION

s92

Ky.P.S.C. 2000

[KY.] Accumulated depreciation -- Property subject to depreciation -- Plant funded by customer advances -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

13.

VALUATION

s250

Ky.P.S.C. 2000

[KY.] Plant funded by customer advances -- Inclusion in calculation of depreciation expense -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

14.

VALUATION

s192

Ky.P.S.C. 2000

[KY.] Property included or excluded -- Long-term deferred credit balances -- Pension and postretirement benefit expense accruals -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

15.

VALUATION

s192.1

Ky.P.S.C. 2000

[KY.] Property included or excluded -- Accumulated deferred income taxes (ADIT) -- Exclusion of ADIT associated with supplemental executive retirement income plan -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

16.

VALUATION

s281

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Net original cost rate base.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

17.

VALUATION

s281

Ky.P.S.C. 2000

[KY.] Natural gas -- Adjusted gas operations capitalization -- Combined electric and gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

18.

APPORTIONMENT

s58

Ky.P.S.C. 2000

[KY.] Combined gas and electric utility -- Adjusted gas operations capitalization -- Natural gas rate proceeding.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

19.

VALUATION

s192.1

Ky.P.S.C. 2000

[KY.] Property excluded -- Job development investment tax credit -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

20.

VALUATION

s226

Ky.P.S.C. 2000

[KY.] Property excluded -- Investment not associated with jurisdictional operations -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

21.

RETURN

s7

Ky.P.S.C. 2000

[KY.] Basis for computation -- Capitalization -- Exclusion of job development investment tax credit -- Exclusion of nonutility investment -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

22.

REVENUES

s5

Ky.P.S.C. 2000

[KY.] Natural gas -- Service fees -- Returned check charge -- Disconnection and reconnection -- Adjustment for fee increases.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

23.

PAYMENT

s53

Ky.P.S.C. 2000

[KY.] Enforcing payment -- Returned check charge -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

24.

RATES

s308

Ky.P.S.C. 2000

[KY.] Disconnection and reconnection charges -- Continuity and gradualism -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

25.

EXPENSES

s99

Ky.P.S.C. 2000

[KY.] Salaries and wages -- Adjustment to reflect union wage increase -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

26.

EXPENSES

s105

Ky.P.S.C. 2000

[KY.] Extra benefits -- 401(k) matching expense -- Adjustment to reflect union wage increase -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

27.

EXPENSES

s106

Ky.P.S.C. 2000

[KY.] Savings in operation -- Reduction in number of employees -- Voluntary retirement program -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

28.

EXPENSES

s81

Ky.P.S.C. 2000

[KY.] Office expense -- Computer costs -- Year 2000 preparedness -- Three- year amortization -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

29.

EXPENSES

s19

Ky.P.S.C. 2000

[KY.] Computer costs -- Year 2000 preparedness -- Three-year amortization -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

30.

EXPENSES

s49

Ky.P.S.C. 2000

[KY.] Pension expense -- Rejection on normalization adjustment -- Rejection of actuarial estimate -- Use of actual test-year level -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

31.

EXPENSES

s26

Ky.P.S.C. 2000

[KY.] Advertising/promotional expense -- Test for inclusion -- Material benefit to ratepayers -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

32.

EXPENSES

s20

Ky.P.S.C. 2000

[KY.] Environmental remediation -- Manufactured gas plant cleanup -- Amortization of deferred expenditures -- Eight-year amortization -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

33.

EXPENSES

s125

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Environmental remediation -- Manufactured gas plant cleanup -- Amortization of deferred expenditures -- Eight-year amortization.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

34.

EXPENSES

s92

Ky.P.S.C. 2000

[KY.] Rate case expense -- Three-year amortization -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

35.

EXPENSES

s20

Ky.P.S.C. 2000

[KY.] Injuries and damages -- Removal of abnormal settlement payments -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

36.

EXPENSES

s48

Ky.P.S.C. 2000

[KY.] Dues -- Electric Power Research Institute -- Disallowance -- Direct benefits test -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

37.

EXPENSES

s105

Ky.P.S.C. 2000

[KY.] Employee benefits -- Moving expenses -- Disallowance -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

38.

EXPENSES

s125

Ky.P.S.C. 2000

[KY.] Combined electric and gas utility -- Common expenses -- Allocation to gas operating expenses -- Updated allocation factors -- Gas rate proceeding.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

39.

EXPENSES

s63

Ky.P.S.C. 2000

[KY.] Outside legal expense -- Combined electric and gas utility -- Direct assignment requirement -- Disallowance of inappropriately allocated expenses -- Gas rate proceeding.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

40.

ACCOUNTING

s12.1

Ky.P.S.C. 2000

[KY.] Outside legal expense -- Combined electric and gas utility -- Direct assignment requirement.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

41.

EXPENSES

s105

Ky.P.S.C. 2000

[KY.] Incentive compensation awards -- Adjustments to reflect voluntary retirements and union wage increase -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

42.

EXPENSES

s19

Ky.P.S.C. 2000

[KY.] Depreciation -- Adjustments to test period -- Common plant allocation -- Combined utility -- Natural gas rate proceeding.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

43.

EXPENSES

s114

Ky.P.S.C. 2000

[Ky.] Income taxes -- Interest synchronization adjustment -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

44.

EXPENSES

s114

Ky.P.S.C. 2000

[KY.] Income taxes -- Exclusion of prior period income tax adjustments -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

45.

RETURN

s26.1

Ky.P.S.C. 2000

[KY.] Reasonableness -- Capital structure -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

46.

RETURN

s26.2

Ky.P.S.C. 2000

[KY.] Reasonableness -- Cost of long- and short-term debt -- Updated cost rates -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

47.

RETURN

s26.3

Ky.P.S.C. 2000

[KY.] Reasonableness -- Cost of preferred stock -- Updated cost rate -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

48.

RETURN

s26.4

Ky.P.S.C. 2000

[KY.] Reasonableness -- Cost of equity -- Estimation methodologies -- Proxy group of comparison companies -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

49.

RETURN

s26.4

Ky.P.S.C. 2000

[KY.] Reasonableness -- Cost of equity -- Effect of weather normalization adjustment clause -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

50.

RETURN

s92

Ky.P.S.C. 2000

[KY.] Natural gas -- Rate of return on rate base.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

51.

APPORTIONMENT

s30

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Distribution costs -- Demand component -- Customer component -- Zero intercept methodology.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

52.

RATES

s373

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Allocation of distribution costs -- Demand component -- Customer component -- Zero intercept methodology.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

53.

APPORTIONMENT

s11

Ky.P.S.C. 2000

[KY.] Particular expenses -- Distribution mains -- Demand component -- Customer component -- Zero intercept methodology -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

54.

APPORTIONMENT

s30

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Fixed storage costs -- Allocation to firm customers.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

55.

RATES

s373

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Allocation of fixed storage costs -- No allocation to interruptible classes.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

56.

APPORTIONMENT

s30

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Cost allocation -- Customer service and sales expense.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

57.

RATES

s373

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Cost allocation -- Customer service and sales expense.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

58.

RATES

s373

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Revenue allocation -- Movement toward fully allocated cost recovery -- Exceptions for special contract and economic development customers.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

59.

RATES

s380

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Special factors -- Competition -- Avoiding bypass.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

60.

RATES

s378

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Residential customer charge -- Gradual movement toward cost of service.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

61.

RATES

s378

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Customer charges -- Two-tiered charge for commercial and industrial classes.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

62.

AUTOMATIC ADJUSTMENT CLAUSES

s34

Ky.P.S.C. 2000

[KY.] Weather normalization adjustment clause -- Revenue stabilization -- Natural gas utility.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

63.

RATES

s384

Ky.P.S.C. 2000

[KY.] Natural gas rate design -- Transportation service -- Tariff modifications.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

64.

EXPENSES

s125

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Main replacement program -- Discussion.

Re Louisville Gas and Electric Company

P.U.R. Headnote and Classification

65.

VALUATION

s281

Ky.P.S.C. 2000

[KY.] Natural gas utility -- Main replacement program -- Capital investment -- Avoiding earnings erosion -- Discussion.

Re Louisville Gas and Electric Company

BY THE COMMISSION:

ORDER

Louisville Gas and Electric Company ('LG&E'), a wholly owned subsidiary of LG&E Energy Corporation ('LG&E Energy'), is an electric and gas utility that purchases, sells, stores, transports and distributes natural gas in Jefferson County and in portions of Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble and Washington counties in Kentucky. [FN1]

BACKGROUND

On February 22, 2000, LG&E filed a letter giving notice of its intent to file an application for approval of an increase in its gas rates to produce additional annual revenues of $27,911,790, an increase of 14.53 percent. [FN2] On March 30, 2000, LG&E filed its application. LG&E's application includes proposals to establish a Weather Normalization Adjustment Clause ('WNA Clause ') and to amend its tariffs to provide gas main extensions differently than that required by 807 KAR 5:022, Section 9(16)(a), (b) and (c). To determine the reasonableness of the request, the Commission suspended the proposed rates for five months from their effective date pursuant to KRS 278.190(2) up to and including September 28, 2000.

On April 21, 2000, LG&E filed an application to increase certain non-recurring charges for both its electric and gas customers. [FN3] Based upon review of LG&E's applications, the motion of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ('AG'), to consolidate LG&E's proceedings and the responses thereto, the Commission ordered the two proceedings consolidated into Case No. 2000-080 and directed that Case No. 2000-137 be closed.

The following parties requested and were granted full intervention : The AG; Kentucky Industrial Utility Customers ('KIUC'); The United States Department of Defense and other Federal Executive Agencies ('DOD'); People Organized and Working for Energy Reform ('POWER'); and Metro Human Needs Alliance ('MHNA'). Initially, Robert L. Madison was granted full intervention; however, the scope of his participation was limited to the electric non- recurring charge issues on a finding that he was not a gas customer and therefore did not meet the regulatory standard for full intervention.

On April 6, 2000, the Commission issued a procedural schedule to investigate LG&E's rate application. [FN4] The schedule provided for discovery, intervenor testimony, rebuttal testimony by LG&E, a public hearing, and an opportunity for the parties to file post-hearing briefs. LG&E filed its rebuttal testimony on July 26, 2000. LG&E's rebuttal testimony contained revisions to key exhibits that resulted in a requested adjustment of $26,376,773 rather than the originally proposed $27,911,790. KIUC also filed rebuttal testimony on July 26, 2000, which the AG, POWER, and MHNA moved to strike. The Commission overruled the motions to strike KIUC's rebuttal testimony at the public hearing held at the Commission's offices in Frankfort, Kentucky on August 2, 3, and 4, 2000. [FN5]

At the conclusion of the hearing, the Commission modified the procedural schedule to permit the parties up to and including September 8, 2000 in which to submit briefs. All parties timely filed briefs and the case now stands submitted for a decision.

TEST PERIOD

[1] LG&E proposes the 12-month period ending December 31, 1999 as the test period for determining the reasonableness of the proposed rates. The AG and DOD also utilized this 12-month period. The Commission finds it is reasonable to utilize the 12-month period ending December 31, 1999 as the test period in this proceeding. In utilizing a historic test period, the Commission has given full consideration to appropriate known and measurable changes.

CAPITALIZATION VERSUS RATE BASE

[2-4] LG&E determined that its adjusted test-year capitalization is $268,202,448, while its adjusted test-period net original cost rate base ('rate base') is $287,909,011. [FN6] LG&E's proposed increase in revenue results from the application of the overall cost of capital to its adjusted test-period rate base.

LG&E acknowledges that for its combined electric and gas operations, its revenue proposals have historically been based on capitalization rather than on rate base. As this proceeding deals only with its gas operations, LG&E states that it sought guidance from the Commission's decision in Case No. 99-176, [FN7] the most recent gas-only rate case. LG&E notes that in Case No. 99- 176, the AG recommended, and the Commission determined, that the revenue increase for Delta Natural Gas Company, Inc. ('Delta') should be based on rate base rather than capitalization. LG&E argues that it was following the most recent applicable precedent when it used rate base instead of capitalization to determine its proposed revenue increase. [FN8] LG&E contends that the Commission's determination of the return requirement using rate base in Delta's last two general rate cases constitutes a change in Commission policy for calculating the return requirement. LG&E claims there was nothing extraordinary about the latest Delta rate case that would have necessitated changing the Commission's policy of using capitalization. [FN9] LG&E repeatedly states that it is unaware of any other jurisdiction using capitalization to determine the return requirement. [FN10] LG&E also notes that, for combined electric and gas utility, the capital structure cannot be directly separated between the two operations, while a separate rate base is calculated for both electric and gas operations. [FN11] In its rebuttal testimony and brief, LG&E extensively criticizes the AG for advocating that the return requirement be determined using capitalization. LG&E repeatedly notes that the AG supported using the rate base in the two previous Delta general rate cases. [FN12]

The AG recommends that LG&E's revenue requirement be calculated by applying the overall cost of capital found reasonable to LG&E's investment that is used and useful in providing service to the ratepayers. The AG contends that this investment has been financed by investor-supplied capital, which is composed of debt, preferred stock, and equity. [FN13] Thus, the AG bases his revenue requirement recommendation on LG&E's capitalization rather than on its rate base. The AG states that when a utility's capitalization exceeds its rate base, this generally indicates that a portion of the capitalization has been used to finance non-regulated, non-utility, or 'below-the-line' assets. The AG further asserts that when a utility's rate base exceeds its capitalization, portions of the rate base may have been financed with funds from sources other than debt, preferred stock, and common equity. Such a situation could also indicate that the inclusion of rate base items determined by formulas, such as the cash working capital allowance, do not actually exist. [FN14] The AG states that the use of LG&E's gas capitalization is consistent with the Commission's recent decision in Case No. 98-426. [FN15] The AG further claims that it would be inconsistent and inappropriate to determine that LG&E's electric return requirement should be based on capitalization and then, within a few months, to determine that LG&E's gas return requirement should be based on rate base. [FN16] Finally, the AG contends that it is doubtful LG&E would have urged the Commission to adhere to the decision in the Delta case to base the revenue requirement on rate base, in light of the Commission's traditional approach of using capitalization in LG&E general rate cases, if LG&E's gas capitalization had been larger than its gas rate base. [FN17]

The DOD determined its recommended revenue increase for LG&E using rate base, but took no position on whether the revenue requirements should be calculated using rate base or capitalization. [FN18]

As noted previously, the Commission has determined the revenue requirements for LG&E using capitalization rather than rate base. This was true for LG&E's last combined electric and gas general rate case, Case No. 90-158, [FN19] as well as the recent electric rate complaint case, Case No. 98-426. However, if justification exists, the Commission will consider using an approach different from that previously used. LG&E has based its argument supporting the use of rate base on the Commission's decision in Delta's recent gas rate case. Accordingly, it is appropriate here to analyze the Delta case and to determine whether the reasoning in that case applies here.

In Case No. 99-176, the Commission determined that Delta's rate base was $91,997,648 and its capitalization was $92,996,779. [FN20] Delta's revenue requirement was determined by applying the overall cost of capital to the rate base. There is no discussion in that Order explaining why rate base was utilized. However, the Commission notes that the rate base was the lower of the two valuations of Delta. The Commission has also reviewed Delta's previous general rate case, Case No. 97-066. [FN21] The Commission determined that Delta's rate base was $65,445,709 and its capitalization was $65,949,247. [FN22] As in Case No. 99-176, Delta's revenue requirement was determined by applying the overall cost of capital to the rate base, and there is no discussion explaining why rate base was utilized. In the December 8, 1997 Order, the rate base was the lower of the two valuations of Delta. In the May 1, 1998 Order, the revenue requirements were still determined using rate base, even though it was slightly higher than capitalization.

Delta is a Kentucky corporation that purchases, sells, stores, transports, and distributes natural gas to approximately 38,000 customers in 23 Kentucky counties. It has a wholly owned subsidiary that provides gas storage services to Delta. [FN23] LG&E is a Kentucky corporation that is engaged in the electric and gas businesses. LG&E's gas business purchases, sells, stores, transports, and distributes natural gas to approximately 293,000 customers in 16 Kentucky counties. LG&E has no subsidiaries, but is one of two regulated utilities owned by LG&E Energy.

After reviewing Delta's two previous rate cases and comparing Delta and LG&E, the Commission rejects LG&E's arguments that our decisions in the Delta cases constitute 'applicable precedent' and a change in Commission policy for calculating the revenue requirements for a utility. Since it has been 10 years since LG&E's last general rate case for gas operations, and since this is the first time it has filed a separate gas case, it is understandable that LG&E would review recent gas case decisions. But it is equally valid to review past Commission decisions involving the other combined electric and gas utility under our jurisdiction, The Union Light, Heat and Power Company. [FN24] Both reviews must, however, be considered in light of the Commission's previous determinations of LG&E's revenue requirements.

When determining the valuation of a utility to be used in calculating revenue requirements, the Commission is guided by KRS 278.290(1), which states in part:

> In fixing the value of any property under this subsection, the commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for rate-making purposes.

The Commission has previously found that LG&E's revenue requirement should be determined by using capitalization rather than rate base. However, this does not preclude the Commission from determining that the revenue requirement in this proceeding should be based on rate base, if evidence is presented to support such a finding. In this proceeding, LG&E has not provided any evidence to justify the use of its rate base to determine revenue requirements, other than stating this was the approach used in the Delta proceeding and in other jurisdictions. LG&E also has not provided any evidence explaining why the circumstances faced by Delta in its previous rate cases are relevant to LG&E's situation.

As we acknowledged in Case No. 98-426, while rate base and capitalization theoretically should be equal, it is rare that this happens. [FN25] Because rate base and capitalization are rarely equal, the Commission promulgated 807 KAR 5:001, Section 10(6)(i), which requires a utility to file a reconciliation of its rate base and capitalization used for determining revenue requirements in a historic test-year rate application. This reconciliation should identify the reasons for the difference between the two valuation approaches. LG&E provided reconciliations for both its total company and its gas operations. While no party to this proceeding has challenged LG&E's reconciliations, the Commission did question LG&E about the reconciliations and sought clarifications of the information provided. [FN26] LG&E's reconciliations do not identify and explain the reasons for the differences between rate base and capitalization, but instead classify its balance sheet as one of the following: rate base, capitalization, non-rate base assets and liabilities, or Commission adjustments to rate base. Of particular concern in the gas operations reconciliation is the inclusion of an 'Electric/Gas Adjustment' which, LG&E states, results from the use of different allocation percentages when determining separate electric and gas balance sheets. [FN27] This 'Electric/Gas Adjustment' is nearly double the amount of the difference between the gas rate base and gas capitalization. Consequently, LG&E's reconciliations of rate base and capitalization provide little information as to why the difference between gas rate base and gas capitalization is $19,706,563. [FN28]

LG&E's statement that this is the only jurisdiction using capitalization to determine revenue requirements is of no relevance. The Commission is not restricted by the approaches other regulatory commissions have employed to determine revenue requirements. We also note that LG&E has produced no evidence that supports this conclusion.

The Commission observes that, while LG&E does calculate a separate rate base for both the electric and gas operations, it maintains the balance sheet accounts on a combined basis. [FN29] While many of the balance sheet accounts can be identified as pertaining to either electric or gas operations, LG&E must allocate several accounts that are common to both operations. Thus, the implication that LG&E's gas rate base is composed exclusively of directly assigned, gas-only account balances is misleading.

The Commission finds that LG&E's gas revenue requirement should be determined by applying the overall cost of capital to the gas capitalization. The capitalization of the utility is a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility. To impute the operating income requirements based on an inflated rate base in effect establishes a cost of doing business that is non-existent to the utility. LG&E's arguments that Commission decisions in recent Delta rate cases constitute applicable precedent and a change in policy are not persuasive. The Commission is inclined to agree with the AG's observation that when rate base exceeds capitalization, this indicates that portions of rate base have been financed with funds from sources other than debt, preferred stock, and common equity. We also agree with the AG that, given the decision in Case No. 98-426 and the absence of evidence to justify the use of rate base, it is inappropriate to determine LG&E's gas revenue requirement using rate base.

COMMON UTILITY STUDY

[5, 6] LG&E conducts an annual common utility study each November that determines the ratio to be used to allocate its common utility plant to its electric and gas operations. Although conducted in November of each year, the study is not concluded and the results reported to LG&E's management until the following spring. During the test year, LG&E applied the results from the 1998 Common Utility Study ('1998 Study'), which caused common utility plant to be allocated 75 percent to electric and 25 percent to gas. The 1998 Study was performed during November 1998 and submitted to management in January 1999. [FN30] LG&E performed its 1999 Common Utility Study ('1999 Study') during November 1999 and submitted the results to management in April 2000. The 1999 Study indicated that common utility plant should be allocated 77 percent to electric and 23 percent to gas. [FN31]

In its application, LG&E used the 1998 Study when calculating its gas rate base. LG&E contends that it is appropriate to use the 1998 Study because the results from the 1999 Study were not known and measurable when the case was filed. [FN32] LG&E states its belief that the use of the 1998 Study is more appropriate because it contains the information actually used to allocate common utility plant during the test year. [FN33] LG&E also argues that the results of the annual studies vary from year to year and that there is no reason to believe that the 1999 Study is a better predictor of financial results than the 1998 Study. [FN34] In its rebuttal testimony and brief, LG&E criticizes the AG for advocating the use of the 1999 Study results, stating that if the 1999 Study is used, other common utility expense allocation factors that were changed at the beginning of 2000 should also be recognized. [FN35] LG&E further notes that the 1998 Study was used to allocate the common utility plant in Case No. 98-426, and argues that it would be inconsistent for the AG to advocate the use of the 1999 Study while at the same time opposing LG&E's proposal to determine its revenue requirements using rate base. [FN36]

The AG recommends that the results of the 1999 Study be used for rate-making purposes in this case. The AG argues that the common utility allocation factor of 23 percent to gas should be used because it is a known and measurable number, it results from the most recent common utility study, and it is based on 1999 actual accounting data. [FN37]

The Commission agrees with the arguments put forth by the AG. The results of the 1999 Study are known and measurable, reflect the most recent version of a recurring analysis of allocation factors, and are based on actual accounting data that corresponds with the test period. The Commission also agrees with LG&E that, consistent with the use of the 1999 Study, the updated allocation factors for the common operating expenses should also be reflected in the determination of LG&E's gas operating expenses. [FN38] The Commission reminds LG&E that the purpose of its annual common utility study should be to establish the appropriate allocation factor used to allocate the common utility plant to its electric and gas operations. The Commission rejects LG&E's contention that the 1998 Study should be used in this proceeding because it was used in Case No. 98-426. The test period in Case No. 98-426 was the 12 months ending December 31, 1998; in this case it is the 12 months ending December 31, 1999. There also is no relevance in LG&E's argument connecting the use of the 1999 Study to support its proposal to determine revenue requirements using rate base. Therefore, the Commission will apply the results of the 1999 Study and the updated common operating expense allocation factors when determining the rate base, capitalization, and net operating income of LG&E in this proceeding.

RATE BASE

LG&E proposes an adjusted gas operations rate base of $287,909,011. [FN39] The AG proposes an adjusted gas operations rate base of $277,961,350. [FN40]

The DOD adopts the adjusted gas operations rate base as determined by LG&E. [FN41] The Commission has reviewed the proposed rate bases and has made the following modifications:

Utility Plant

[7] LG&E has determined that its total gas utility plant in service at the end of the test period was $439,581,248. [FN42] The AG has determined that the total gas utility plant in service was $436,334,493. [FN43] The difference in the amounts results from the AG allocating the common utility plant in service and common CWIP using the 1999 Study rather than the 1998 Study. As discussed previously in this Order, the Commission has determined that the 1999 Study should be used in the determination of LG&E's gas operations rate base. Therefore, the Commission will accept the total gas plant in service determined by the AG as the appropriate test-period balance.

Prepayments

[8, 9] In determining the gas operations rate base, LG&E and the AG use the 13-month average balance for prepayments. [FN44] LG&E provided the ratios used to determine the portion of the total company prepayments allocated to gas operations.

The Commission has reviewed these allocation ratios and has rejected the ratios used for the prepaid real estate commissions and prepaid rights-of-way. LG&E allocates prepaid real estate commissions on a service center that is shared by both the electric and gas businesses on a 50-50 basis. The Commission believes that the service center is part of common utility plant that should be allocated in accordance with the 1999 Study. LG&E's test-period allocation of the prepaid rights-of-way reflects the 1998 Study; however, the Commission has determined the 1999 Study should be used. The Commission's determination of prepayments reflects these allocation ratio changes. [FN45]

The prepaid taxes included in the prepayments reflect the gas portion of the PSC Assessment. The Commission has previously found that the PSC Assessment should be excluded from the calculation of rate base. The Commission stated in Case No. 98-474:

> The classification of the PSC Assessment as a prepayment allows KU to recognize the expense over the entire year, rather than in the month of payment. The Commission is not opposed to the concept of spreading this expenditure over a 12-month period. However, in determining whether the unamortized expense should be included in rate base, we must consider whether the funds were provided by ratepayers prior to or after the prepayment is recorded on the books. The assessment is based on the gross operating revenues of the utility for the prior calendar year, and it is notified of its assessments by July 1 of the following year. Thus, the assessment applies to sales that occurred prior to the recording of the prepayment. The PSC Assessment is included in operating expenses in determining revenue requirements that provide full recovery of this cost. It is inappropriate to also include a return on the unamortized balance in the prepaid accrual simply because for accounting purposes the assessment can be treated as an accrual or a prepaid expense. [FN46]

While LG&E acknowledges the Commission's traditional treatment of the PSC Assessment, it believes that the PSC Assessment should remain in the prepayments because it is a cash outlay for a prepaid expense and should be treated in the same manner as other prepaid items. [FN47] The Commission is not persuaded by LG&E's argument. LG&E has not provided any evidence that would refute the Commission's previous decisions. Based on the same reasoning set forth in Case No. 98-474, the Commission finds that the PSC Assessment should be excluded from the 13-month average balance of prepayments included in LG&E's gas rate base.

Cash Working Capital Allowance

[10] LG&E and the AG determine the cash working capital allowance using the 45 day or 1/8 formula methodology, reflecting the impacts of adjustments each proposed th to gas operation and maintenance expenses. While the Commission finds that approach is reasonable and should be used here, the cash working capital allowance included in the Commission's determination of gas rate base has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses, as discussed later in this Order.

Accumulated Depreciation

[11-13] LG&E proposes to increase the test-period balance for gas accumulated depreciation of $148,052,866 by $80,513 in conjunction with its proposed adjustment to depreciation expense. The proposed adjustment is to reflect a full year depreciation expense on 1999 net plant additions, in order for the test period to be more representative of ongoing operations. LG&E calculates its proposed adjustment by listing test-period end plant balances by function multiplied by the corresponding depreciation rate. [FN48] LG&E's test-period balance for gas accumulated depreciation and its proposed depreciation expense adjustment reflect the allocation of depreciation expense on common utility plant and miscellaneous intangible plant, both of which are allocated to gas operations using the 1998 Study.

The AG proposes to adjust the test-period balance for gas accumulated depreciation to $147,012,854, to reflect the use of the 1999 Study, and further to reduce this accumulated depreciation by $467,195 [FN49] in conjunction with its proposed adjustment to depreciation expense. The AG's proposed depreciation expense is composed of two items. First, the AG recalculates LG&E's depreciation expense adjustment so that it reflects the 1999 Study. Second, the AG removes depreciation expense on plant funded by customer advances for construction ('customer advances'). The AG contends that since LG&E is not seeking a return on plant funded by customer advances, it is inappropriate and inconsistent for LG&E to include plant funded by customer advances in the calculation of the depreciation expense adjustment. [FN50]

LG&E disagrees with the AG's exclusion of plant funded by customer advances from the calculation of depreciation expense. LG&E contends that as the customer advances are refunded over a 10-year period, a corresponding amount of the customer advances is charged off, which effectively means that LG&E pays for that utility plant. Any portion of the customer advance not refunded within the 10-year period is reclassified as a contribution in aid of construction, and that portion of the utility plant is deducted from the balance of utility plant in service. LG&E argues that the AG's proposal would require that depreciation on plant funded by customer advances be held in abeyance until LG&E's refunding obligation had expired. LG&E further argues that the AG's proposal is inconsistent with the proper accounting treatment for customer advances and the Commission's past rate-making treatment. [FN51]

As the Commission has determined that the 1999 Study should be used in this proceeding, we have restated LG&E's test-period balance for gas accumulated depreciation to $147,012,854. The Commission has also recalculated LG&E's depreciation expense adjustment, applying the 1999 Study to the common utility plant and miscellaneous intangible plant, and the result is a reduction to the test-period expense of $167,448. Therefore, the Commission will include this reduction in test-period depreciation expense in the balance of accumulated depreciation used to determine LG&E's gas rate base.

However, the Commission agrees with LG&E that the AG's proposal to exclude depreciation expense on plant funded by customer advances is inappropriate. The Commission finds that portion of the AG's proposal to be inconsistent with established accounting and rate-making treatments. We agree with LG&E that such an approach would require the utility to wait until the refunding period is concluded before recovering depreciation expense on utility plant funded by customer advances.

Miscellaneous Long-Term Liabilities

[14] The AG proposes that $6,934,924 in certain long-term deferred credit balances be recognized as reductions to LG&E's gas rate base. [FN52] The AG argues that these accruals, which are internally funded, represent funds that would be available to LG&E for general working capital purposes. The AG believes these accruals should be treated as reductions to LG&E's gas rate base. [FN53]

LG&E opposes the AG's proposed adjustment related to these miscellaneous long- term liabilities, noting that such adjustments are contrary to the Commission's long-standing practice for determining rate base. LG&E also notes that these accruals have nothing to do with the investment in facilities used to provide service to customers. [FN54]

The Commission is not persuaded by the AG's arguments. The AG has offered no evidence to support this adjustment to rate base and has not explained why, given the nature of these accruals, it is reasonable to assume these internally funded accruals represent funds available for general working capital purposes. Therefore, the Commission rejects the AG's proposal.

Accumulated Deferred Income Taxes ('ADIT')

[15] In the determination of its gas rate base, LG&E has deducted ADIT of $26,352,941. [FN55] The balance utilized by LG&E included common ADIT reflecting the 1998 Study. The AG has deducted ADIT of $27,235,152. [FN56] The AG's balance for gas ADIT reflects the use of the 1999 Study for the allocation of common ADIT, and several adjustments. First, the AG proposes to exclude ADIT related to test period over-and under-recovery balances of LG&E's Gas Supply Clause ('GSC') mechanism. Second, the AG proposes to exclude ADIT related to LG&E's Supplemental Executive Retirement Income Plan ('SERP'). Finally, the AG proposes that, if the Commission rejects his recommendation concerning the miscellaneous long-term liabilities, the ADIT balances related to those accruals should be excluded from the rate base calculation. [FN57]

LG&E opposes the AG's adjustments to the gas ADIT balances. LG&E states that the GSC mechanism does not contain provisions for the recovery of taxes or deferred taxes. LG&E contends that if the ADIT associated with the GSC mechanism is excluded from rate base, then this cost would never be recoverable. LG&E notes that such an exclusion is not consistent with the approach used by the Commission to determine rate base. [FN58] Concerning the proposal to exclude ADIT associated with SERP, LG&E argues that it must pay these taxes associated with the SERP accruals and that because this portion of the ADIT balance relates to SERP does not warrant the AG's proposed exclusion. [FN59] Concerning the ADIT related to miscellaneous long-term liabilities, LG&E opposes this adjustment for the same reasons given in opposition to the AG's miscellaneous long-term liabilities adjustment. [FN60]

As noted previously in this Order, the Commission has determined that the 1999 Study should be used in this proceeding, and the adjusted gas ADIT balance reflects this decision. In addition, the Commission agrees with the AG that the gas ADIT associated with LG&E's SERP should be excluded from the rate base calculation. Because LG&E records SERP expenses and related income taxes as 'below-the-line' expenses on its income statement, the shareholders of LG&E bear these expenses. It is consistent that the associated ADIT should also be borne by shareholders, and the gas ADIT utilized by the Commission to determine LG&E's gas operations rate base will reflect this exclusion. [FN61]

However, the Commission is not persuaded by the AG's arguments concerning the remaining proposed adjustments to ADIT. The GSC mechanism currently does not contain a provision addressing the recovery of taxes or deferred taxes. Excluding ADIT associated with the GSC mechanism would deny LG&E the opportunity to earn a return on these deferred taxes. The AG has provided no evidence to support excluding the ADIT related to the GSC or miscellaneous long-term liabilities. The AG has also failed to adequately explain why the Commission should recognize these adjustments when it has not done so previously. Therefore, the Commission rejects these proposed adjustments to the ADIT.

[16] Based upon the previous findings, we have determined the gas rate base for LG&E at December 31, 1999 to be as follows:

Total Utility Plant in Service	$436,334,493				
Add: Gas Stored Underground	26,664,564 Materials and	1,371,734 Prepayments	244,443 Cash	4,733,447	____

	Supplies		Working Capital Allowance	
Subtotal	$ 33,014,188			
Deduct:	146,845,406	10,444,203	26,462,743	29,222
Accumulated Depreciation	Customer Advances	Accumulated Deferred Taxes	Investme-nt Tax Credit (prior law)	
Subtotal	$183,781,574			
NET ORIGINAL COST RATE BASE -- GAS	$285,567,107			

CAPITALIZATION

[17-21] LG&E proposes an adjusted gas operations capitalization of $268,202,448. [FN62] Included in the gas capitalization were adjustments for the Job Development Investment Tax Credit ('JDIC') and the exclusion of the gas portion of LG&E's investment in the African American Venture Capital Fund ('Venture Fund'), an investment not associated with LG&E's Kentucky jurisdiction operations. Both adjustments were allocated by LG&E on a pro rata basis to all components of capitalization. The AG initially agreed with the adjusted gas operations capitalization proposed by LG&E. However, in order to maintain consistency with the recommendation to reflect the 1999 Study, the AG now proposes an adjusted gas operations capitalization of $266,263,516. [FN63] Like LG&E, the AG included adjustments for JDIC and the Venture Fund, allocated on a pro rata basis to all components of capitalization.

Both LG&E and the AG determined the gas capitalization by multiplying LG&E's total company capitalization times a ratio calculated by dividing the gas rate base by the total company rate base. This approach is consistent with the approach used by the Commission in previous LG&E rate cases. LG&E's gas capitalization reflects the impacts of the 1998 Study as it was applied to rate base components and the gas portion of the Venture Fund. The AG's revised gas capitalization reflects the impacts of the 1999 Study as it was applied to rate base components, but reflects the 1998 Study when determining the gas portion of the Venture Fund. Neither LG&E nor the AG reflected the allocation of common JDIC to the gas capitalization. [FN64] To be consistent in the treatment of common items, the common JDIC should have also been allocated to the gas operations.

Based on the findings herein, the Commission has determined that LG&E's test-period-end gas capitalization should be $266,376,827. The Commission's conclusion reflects the impacts of the 1999 Study as applied to the determination of LG&E's gas rate base, as well as the allocation to gas operations of the common JDIC and Venture Fund. The calculation of the gas capitalization is shown on Appendix C.

REVENUES AND EXPENSES

For the test period, LG&E reports actual net operating income from gas operations of $7,282,920. [FN65] LG&E proposes a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, which results in an adjusted net operating income from gas operations of $7,614,330. [FN66] The AG proposes his own series of revenue and expense adjustments to arrive at his adjusted net operating income from LG&E's gas operations of $11,258,219. [FN67] The Commission finds that six of the adjustments proposed by LG&E and accepted by the intervenors are reasonable and will be accepted without change: temperature normalization; year-end customer growth; customer switching and billing; the removal of the Muldraugh storage field gas storage losses; the elimination of the LG&E Energy expenses allocated to LG&E's gas operations; and the impact of the post test-period union wage increase upon payroll taxes. [FN68] The Commission makes the following modifications to the remaining proposed adjustments:

Charges For Miscellaneous Service Fees

[22-24] On April 21, 2000, LG&E filed a request to increase its fees for disconnecting and reconnecting service and for returned checks for both its electric and gas customers. [FN69] LG&E proposes to increase the fee for disconnecting and reconnecting service from $14.00 to $23.00 and the fee for returned checks from $4.00 to $10.00. LG&E has provided cost justification for this increase in fees. The changes in these fees result in an additional $38,903 of revenues.

The AG opposes any increase to these fees, citing the increased burden to low-income ratepayers and arguing that increases of this magnitude would violate the Commission's policy of maintaining gradualism and rate continuity when making rate adjustments. [FN70] MHNA also takes the position that the proposed increases will be an undue hardship on low-income customers, [FN71] but neither the AG nor MHNA offers any alternative rates.

The Commission generally recognizes that fees such as these allocate costs to cost causers and are a fair and reasonable component of a gas utility's rate design. However, we also recognize that any increase in utility rates or charges has the potential to create a financial hardship for low-income customers. In this instance, the Commission will approve a fee of $18.50 for disconnecting and reconnecting service and a returned check charge of $7.50 to partially compensate LG&E for its increased costs. This results in an additional $20,892 of revenues. By increasing these charges by one-half of the amount proposed by LG&E the Commission is adhering to the rate-making concepts of continuity and gradualism in order to lessen the impact of these increases on the customers that incur these charges. However, we do so recognizing that the costs not recovered in these charges must then be recovered through LG&E's rates for gas service.

Wages and Salaries

[25] LG&E proposes to increase its wages and salaries expense by $324,268. Under the terms of the 1998 bargaining agreement with the International Brotherhood of Electric Workers, Local 2100, LG&E's union employees will receive a 3.5 percent wage increase on November 13, 2000, which is the basis of LG&E's wage and salary adjustment. [FN72]

The DOD argues that because the union wage increase does not go into e ffect until November 2000, LG&E should be entitled only to the portion of the increase that will be in effect within one year of the test period. [FN73] For this reason the DOD proposes to reduce LG&E's wages and salaries adjustment by $249,768.

LG&E's proposal to reflect the post test-period union wage increase is consistent with the methodology proposed by LG&E and accepted by this Commission in Case Nos. 8616, [FN74] 10064, [FN75] and 90-158. This past methodology recognizes that the contract union wage increase constitutes a known and measurable adjustment. The DOD has not presented any evidence to persuade the Commission to abandon this approach. Accordingly, the Commission finds that LG&E's proposed adjustment should be accepted and has increased salaries and wages expense by $324,268.

401(k) Company Match

[26] LG&E's original proposal was to increase its 401(k) company matching expense by $8,857 to reflect the effect its post test-period union wage increase will have on this expense. [FN76] The AG proposes to decrease LG&E's 401(k) company matching expense adjustment by $1,820 to correct a mathematical error. [FN77] LG&E agrees with the AG that there is a mathematical error in its calculation, but LG&E has determined that its 401(k) company matching expense adjustment should be reduced to $7,236, which is $200 greater than the AG's proposal. [FN78] Upon review of LG&E's and the AG's calculations, the Commission finds that LG&E's revised calculation is more accurate and, therefore, has increased test-period 401(k) company matching expense by $7,236.

LG&E's One Utility Program

[27] Subsequent to the test period, LG&E Energy offered its employees a voluntary retirement package entitled One Utility Program. LG&E Energy announced that by the end of April 2000, its One Utility Program would result in the elimination of 250 positions company wide, and estimated that 127 positions would be eliminated from LG&E. [FN79] LG&E estimated that the One Utility Program would result in estimated net gas savings of $502,390. [FN80] In computing its net savings LG&E used a 21 percent allocation factor for the annual labor savings, a 25 percent allocation factor for the separation costs, and amortized the separation costs over 3 years. [FN81]

The DOD proposes to decrease test-period operating expenses by $502,390 to reflect LG&E's estimate of the net savings in the gas operations resulting from the One Utility Program. [FN82] The AG agrees with the DOD that LG&E's test- period operations should be adjusted to reflect the impact of the One Utility Program; however, the AG makes several revisions to LG&E's estimate. The AG proposes a net reduction of $838,900 [FN83] by using the same 21 percent allocation factor for both the employee separation costs and the labor savings, and amortizing the separation costs over 5 years. [FN84]

LG&E claims that the savings from its One Utility Program are not known and measurable at this time, and will likely never be known and measurable. LG&E states that they have not implemented a formal process for tracking the savings and that even if they could be measured, there is uncertainty as to what the savings will actually be. [FN85] While it was originally anticipated that 250 employees would leave LG&E Energy company wide, LG&E now asserts that it is unable to determine how many employees will leave because the One Utility Program's non-discrimination practices permit an indeterminate number of employees to take advantage of the program. For this reason, LG&E argues that it does not know how many positions it will need to backfill with new hires or temporary employees or the cost of technology that will be required to accomplish the necessary tasks in light of the employee losses. [FN86]

According to an LG&E witness, the estimated separation costs were recorded in March 2000 and the majority of the employees left as expected in April 2000. [FN87] The Commission finds that the employee reduction that occurred in April 2000 as a result of the One Utility Program will impact LG&E's current and ongoing operations.

LG&E's argument that the impact of its One Utility Program is not known and measurable centers around the claim that company wide there has been an over subscription to the program. [FN88] As of June 30, 2000 a net of 214 employees have left the employment of LG&E. Of this number 124 are connected to the One Utility Program and the remaining 90 can be attributed to retirements and normal attrition. [FN89] This shows that the original estimate that the One Utility Program would result in the elimination of 127 positions at LG&E is within a range the Commission finds is reasonable.

Given that the One Utility Program has been implemented and that the number of positions actually eliminated is known, the Commission finds that LG&E's test-period operations should be adjusted. If this adjustment is not made, the savings will not be passed on to consumers until LG&E's next gas rate case. Likewise, if the adjustment is not included, LG&E will realize additional earnings as a result of those employee eliminations. LG&E's estimate of its net savings in the gas operations is reasonable; however, the actual separation costs incurred as of July 2000 of $7,244,901 [FN90] have been substituted for the estimate, which results in a reduction to test-period operating expenses of $673,693.

Year 2000 Expenses

[28, 29] In accordance with the Commission's decision in Case No. 98-426, LG&E proposes to reduce its operating expenses by $260,710 to reflect a 3-year amortization of the incremental costs associated with preparing its computer systems for the year 2000 ('Y2K Preparedness'). [FN91]

The DOD proposes a reduction to operating expenses of $391,066 to eliminate all of the costs associated with LG&E's Y2K Preparedness on the grounds that they are non-recurring. [FN92] While the AG does not oppose LG&E's recovery of the cost of the Y2K Preparedness, he does object to the proposed 3-year amortization. Because this case is not subject to a 3-year review, as was established in Case No. 98-426, the AG claims that there is no compelling reason to amortize this expense over 3 years. Given the extraordinary nature of this non-recurring expense and considering the magnitude of the rate increase sought, the AG proposes this expense be amortized over 5 years, which results in a reduction to operating expenses of $312,853. [FN93]

In Case No. 98-426, the Commission rejected a proposed 5-year amortization period for Y2K Preparedness expenditures, finding that 'A three year amortization conforms with generally accepted accounting principles and LG&E's procedures for recovery of information technology investments.' [FN94] Neither the DOD nor the AG has presented any evidence to persuade the Commission that this approach is unreasonable. Accordingly, the Commission finds that LG&E's proposed adjustment to reduce operating expenses by $260,710 should be accepted.

Pension Expense

[30] LG&E proposes to increase the allocation of its pension expense to its gas division by $801,704. [FN95] According to LG&E, the pension expense decreased considerably during the test period due to changes in the actuarial assumptions and the strong performance of the pension asset investments. To normalize pension expense, LG&E uses a mathematical 5-year average of historical pension costs. [FN96]

The AG states that the Commission has not previously allowed LG&E to normalize its pension expense based on a 5-year historic average. The AG argues that pension expense is not the type of expense for which a historic averaging is appropriate.

The AG points to a change in the Union Plan provisions in 1999 that resulted in a decrease of $2.225 million in LG&E's pension expenses. Because 4 of the 5 years fail to reflect such changes in the Union Plan provisions, the AG states that it is inappropriate to utilize a historic averaging normalization. The AG proposes a decrease of $1,903,762 to LG&E's adjustment to reflect the impact of the pro forma test period pension expense calculated by LG&E. [FN97]

According to the DOD, LG&E's pension costs have been decreasing for the past 5 years, and there is no indication that this trend will not continue over the next several years. For these reasons the DOD proposes that LG&E's adjustment be denied. [FN98]

LG&E claims that its approach reflects the 20-year market trends preceding 1999, as well as the 1999 market performance, while the AG's approach uses only the results of the investments in 1999 and an estimate of the predicted results of 2000. LG&E argues that it is not appropriate to set rates based on an estimate for the year 2000 that is out of sync with the prior 19 years. Because the official 2000 actuarial report will not be available until early 2001, LG&E claims that the AG's proposal is based upon an actuarial estimate that is on three pages of handwritten notes. For these reasons, LG&E proposes the AG's adjustment be denied. [FN99]

Over the 5-year period of 1995 through 1999 the following events occurred that that would significantly impact LG&E's pension expense:

(1) A net reduction in LG&E's workforce of 410 employees. [FN100]

(2) The merger between LG&E Energy and KU Energy Corporation. [FN101]

(3) The Union Plan provisions were revised in 1999.

(4) The actuarial assumptions were changed in 1999.

(5) The pension assets earned a strong market return in 1999.

Given that the identified events were not reflected in all years, it is unlikely that LG&E's proposal to use a 5-year historical average of these years can be an accurate indicator of LG&E's ongoing expected future levels of pension expense. Likewise, the AG has failed to document that the actuarial estimate of the 2000 pension expense is a reasonable indicator of the future level of LG&E's pension expense. The AG's proposal to use the actuarial estimate also fails to meet the rate-making criteria of known and measurable. For these reasons the Commission finds that the DOD proposal to leave LG&E's pension expense at the test-period level should be accepted.

Advertising/Promotional Expense

[31] LG&E's original proposal was to reduce Account No. 930.1 -- General Advertising Expenses and Account No. 913 -- Advertising Expenses by $60,634 and $21,526, respectively. [FN102] LG&E states that 807 KAR 5:016, Section (2)1, provides that a utility will be allowed to recover for rate-making purposes only those advertising expenses that produce a 'material benefit' to its ratepayers. For this reason LG&E's adjustment only removes the advertising expenses that it deems to be institutional and promotional in nature. [FN103]

The AG proposes a decrease of $205,620, which reflects the removal of additional advertising/promotional expenses of $123,460. [FN104] LG&E agrees with the AG's proposal to remove $45,139 [FN105] of promotional/ advertising expenses identified by the AG that are not the type of expenses the Commission has allowed in the past, and modifies its proposal to remove those expenses. [FN106]

LG&E does not agree with removing the $47,660 in expenses in Account 912001 that relate to economic development. The only justification LG&E provides for this position is that the Commission has traditionally allowed expenses related to the internal economic development activities. To support this claim, LG&E states that these types of expenses were not removed in Case Nos. 90-158 or 98-426. [FN107] The AG views these expenses as promotional and not related to the provision of gas service. [FN108]

The Commission finds that the economic development activities listed in Account 912001 are not specifically identified as those advertising expenditures that have a 'material benefit' for the ratepayers. [FN109] Furthermore, an LG&E witness testified that the FERC definition of Account 912001 matches the Administrative Regulation definition of advertising that is to be excluded from rate-making. [FN110] For these reasons the Commission finds that Account 912001 meets the criteria established by 807 KAR 5:016 as advertising expenses that must be excluded for rate-making purposes and has accepted the AG's adjustment to decrease test-period operating expenses by $205,620, which includes Account 912001.

Manufactured Gas Plant Cleanup Costs

[32, 33] LG&E proposes to increase its test-period operating expenses by $561,612 to reflect the amortization of $1.7 million in costs incurred to cleanup the various contaminates at the manufactured gas plants LG&E formerly owned. [FN111] Because it was concerned that the potential liability to cleanup the manufactured gas plants might be substantial, LG&E recorded the cleanup costs as a deferred debit in accordance with FAS 71. Now that a rate case has been filed, LG&E claims that it is entitled to amortize these expenditures over a reasonable time. For this reason LG&E proposes to amortize these expenditures over 3 years. [FN112]

The AG agrees that the $1.7 million expended on the environmental remediation measures are a one-time non-recurring expenditure that LG&E should be allowed to recover, but contends that the issue is the amortization period. The AG argues that it is appropriate to use the time lapse between the last rate case and this current case and the time period over which the expenditures were deferred as a guide to determine the appropriate amortization period. Therefore, the AG proposes to increase LG&E's test-period operating expenses by $210,604 [FN113] to reflect amortizing the cleanup costs over 8 years, the period of time over which the expenditures were deferred. [FN114]

The DOD agrees with the AG in that LG&E should be allowed to recoup the cleanup costs; however, the DOD recommends that the costs be amortized over 10 years. According to the DOD the contamination of these properties has occurred over an extensive period of time, and the amortization should also be spread over a longer period of time. [FN115] The DOD proposes to increase LG&E's test- period operating expenses by $168,484 to reflect a 10-year amortization period. [FN116]

The only justification expressed by LG&E for its proposal of a 3-year amortization period is that it expects to file a rate case in 3 years. [FN117] The Commission agrees with the AG in that in order to determine a reasonable amortization period for a deferred expenditure it is appropriate to consider the time lapse between the last rate case and this current case and the time period over which the expenditures were deferred. In this instance the cleanup of the manufactured gas plant was started in 1992, [FN118] so the costs have been accumulated over an 8-year period. The Commission finds that the AG's proposal to amortize the manufactured gas plant cleanup costs over 8 years is reasonable and has increased LG&E's operating expenses by $210,604.

Rate Case Amortization

[34] LG&E proposes to increase test-period expenses by $140,000 to reflect the amortization of its estimated rate case expense of $420,000 over a 3-year period. [FN119] The AG does not oppose LG&E's estimated rate case expense, but proposes an increase of $84,000 [FN120] in operating expenses to reflect a 5- year amortization period. The AG argues that there is not a 3-year term Alternative Regulation plan in this proceeding requiring LG&E to file a rate case within 3 years, as there was in Case No. 98-426. The AG further argues that other than LG&E's general statement , there is no evidence in the record that would support LG&E's claim that it will file a gas rate case in 2003. What is known, the AG states, is that LG&E's last gas rate case was 10 years ago in 1990. [FN121] LG&E points to Commission past precedent to support its proposal of a 3-year amortization of rate case expense. [FN122]

This is the first rate case proceeding in which LG&E has requested recovery of rate case expense; therefore, there is no Commission precedent regarding amortization of rate case expense that is LG&E specific. However, the Commission traditionally recommends that a utility seek rate relief in a timely manner, so that rates will gradually increase over time. Finding that 3 years is generally a reasonable period of time between rate cases, the Commission has allowed rate case expense to be amortized over 3 years.

Given the amount of capital LG&E is required to expend on its gas main replacement program, the Commission expects that LG&E will need to seek rate relief within a shorter period of time than in the past. The AG has not presented any evidence to persuade the Commission to abandon its approach of amortizing rate case expense over 3 years. For these reasons the Commission finds a 3-year amortization period is appropriate; however, it has modified LG&E's adjustment to reflect the $296,460 [FN123] in the actual rate case cost that has been incurred to date, which results in an increase to operating expenses of $98,820.

Account 925

[35] LG&E proposes no adjustment in Account 925 -- Injuries and Damages, however, the AG argues that due to the nature of Account 925, it is difficult to predict the annual level of expense for this account. In support of his argument the AG provides a schedule showing that between the period of 1996 through 1999 Account 925 fluctuated from a low of $608,000 to a high of $1,048,000. For this reason, the AG proposes to decrease the test-period level of Account 925 by $253,706 to reflect a 4-year mathematical average. [FN124]

LG&E provided information after the hearing showing that Account 925 includes abnormal expense bookings of $291,000 and $113,400 for non-recurring settlement payments, which are related to certain accidents. [FN125] After reviewing the post-hearing information filed by LG&E, the AG states that it is acceptable to decrease Account 925 by $404,400 to reflect the removal of the abnormal amounts. [FN126]

One method to determine whether an expense level is reasonable is to review the relationship between it and a relevant historical period. As shown by the AG, Account 925 reflects a significant increase in the test-period level when compared to the previous 3 years. LG&E explains that this increase is due to the settlement of an automobile accident and the settlement of a liability claim. Removal of these two abnormal settlement payments from Account 925 results in an adjusted test-period level of $643,883, a level that is reasonable when compared to the 3-year historical amounts. For this reason, the Commission finds that the AG's revised proposal should be accepted and has reduced Account 925 by $404,400.

Account 916

As with Account 925, the AG states that Account 916, miscellaneous sales expenses, also experiences significant fluctuations. The AG argues that LG&E has not provided any information indicating that the test-period level of $53,482 constitutes a trend or that it will be incurred at that level on an ongoing basis in the future. Therefore, the AG recommends that this expense be 'normalized' based on the 5-year historic average of 1995 through 1999 for a decrease of $39,588. [FN127] LG&E argues that the AG offers no evidence that the test-period level of expenses for Account 916 will not be ongoing. [FN128]

As shown by the AG, Account 916 has a significant increase in the test-period level when compared to the previous 4 years. In the information provided after the hearing, LG&E states that the increase is due to misclassification of Gas Sales personnel's labor and expenses in Account Nos. 912 and 880. Given the misclassification of expenses, the AG's comparison of the test-period expense level to the historical amounts is incorrect. For this reason the Commission finds that the AG's adjustment should be denied.

Miscellaneous

[36, 37] The AG proposes that LG&E's test-period operating expenses be reduced by $150,673 to remove several miscellaneous expense items. [FN129] LG&E agrees that $36,101 of the miscellaneous expense items should be removed. However, LG&E disagrees with removing $39,461 of the gas-allocated Electric Power Research Institute ('EPRI') expense and $75,111 for employee moving expenses booked in the test-period. [FN130]

LG&E claims that in Case No. 98-426 the Commission approved inclusion of $294,381 of the EPRI membership charges to its electric operations, which left $37,591 of the EPRI membership charges allocated to the gas division. Because of the Commission's treatment of the EPRI membership charges in Case No. 98- 426, LG&E argues that refusal to allow recovery of the gas allocation in this proceeding will result in the loss of the expenditure for which value is being received. [FN131] Although the Commission has disallowed the recovery of employee moving expenses in the past, LG&E requests the Commission to reconsider this position. According to LG&E if it is not allowed to compensate employees for moving expenses, it would be extremely difficult to hire qualified professional employees from outside the Louisville area. [FN132]

The AG argues that the work performed by EPRI has nothing to do with the provision of gas service in a regulated environment and that for this reason LG&E should not be allowed to recover the gas allocation of the EPRI dues. The AG states that LG&E failed to provide a reasonable explanation to support rate recovery of its employee moving expense and that the Commission should persist in refusing to allow these expenses. [FN133]

The Commission is not persuaded by LG&E's arguments. LG&E's EPRI dues and the allocation of those expenses were not separately examined as part of the proceedings in Case No. 98-426, and the Commission was unaware that the EPRI dues allowed in that proceeding were not reflected at 100 percent. However, such an examination has been part of this case, and LG&E has had the burden of proof to demonstrate that its approaches and methodologies are reasonable. Here, it has not carried that burden. LG&E's incorrect allocation of its EPRI dues and its failure to recover 100 percent of those dues is not a valid reason for the Commission to allow recovery from the gas ratepayers for EPRI services that provide no direct benefit to the gas operations.

LG&E made broad statements regarding its inability to attract and hire qualified professional employees if it is unable to compensate potential employees for their moving expenses. LG&E claims that it has established that the payment of moving expense is necessary to attract qualified employees and states that the expense is recurring. However, at the hearing, an LG&E witness testified that it has not performed an analysis or study to support its statements regarding the payment of moving expenses. [FN134]

The Commission finds that the AG's proposal to eliminate $150,673 of miscellaneous expense items is reasonable and, therefore, is accepted.

1999 Expense Allocation Factors

[38] LG&E argues that if the Commission decides to update rate base and capital structure to reflect the use of the 1999 Study, then it should update the common expenses. [FN135] According to LG&E, updating the common expenses would result in an increase in test-period operating expenses of $1,015,929. [FN136] the Commission agrees with LG&E that, consistent with the use of the 1999 Study, the updated allocation factors for the common operating expenses should also be reflected in the determination of LG&E's gas operating expenses. To update LG&E's test-period operating expenses to reflect the 1999 Study percentages, the Commission will increase expenses by $1,015,929.

Outside Legal Expense

[39, 40] LG&E prepared an analysis of its professional services expenses that identified 26 providers of legal services. On a total company basis, LG&E incurred an expense of $1,087,764. [FN137] LG&E states that it has historically allocated outside counsel expenses between electric and gas operations using the appropriate allocation percentages. LG&E notes that this approach results in some expenses incurred primarily for electric operations being allocated to gas operations and vice versa. [FN138]

During the test period, LG&E recorded these legal expenses in four different expense accounts [FN139] and, using the test-period allocation percentages associated with those accounts, allocated $206,437 of the total company outside legal expense to gas operations. [FN140]

LG&E argues that this allocation approach was used during 1998 and was reflected in the rates set in Case No. 98-426. LG&E believes that it would be unfair to use inconsistent methods for allocating these costs in this case. [FN141] LG&E contends that its allocation methodology for outside legal expenses is appropriate, was approved in Case No. 98-426, and should be approved in this case. [FN142]

In his brief, the AG notes that LG&E's outside legal expenses included a charge of $1,024 for legal work related to telecommunication activities and suggests that outside legal expenses be reduced by that amount. [FN143] LG&E has indicated that this charge should have been recorded below the line and not charged to gas operations. [FN144]

The Commission is not persuaded by LG&E's arguments. LG&E's outside legal expenses and the allocation of those expenses were not separately examined as part of the proceedings in Case No. 98-426. However, such an examination has been part of this case, and LG&E has the burden of proof to demonstrate that its approaches and methodologies are reasonable. If LG&E fails to satisfy its burden of proof, it would be reasonable to expect that the decision reached in this case would not be consistent with what was permitted in a previous case.

As part of its analysis of accounts such as outside legal expenses, the Commission attempts to determine an amount that represents a reasonable, ongoing level of expense to reflect in the utility's rates. When making this determination, the Commission attempts to evaluate whether expenses included in the test period reflect recurring or non-recurring activity. The simple assertion by the utility that the expense level expected in future years would be comparable to the level experienced in the test period is not sufficient. [FN145]

The Commission has made three separate requests of LG&E for descriptions of the legal services provided by the 26 firms. The responses provided have been overall summaries of the services provided that, in many instances, failed to explain why the services should be charged to LG&E's gas operations. [FN146] This lack of specifics concerning the outside legal expenses, and LG&E's approach of allocating all outside legal expenses to electric and gas operations, makes it extremely difficult for the Commission to determine a reasonable, ongoing level at which this expense should be included in rates.

Especially troubling to the Commission is LG&E's allocation of all outside legal expenses to electric and gas operations without consideration for determining which of its operations is responsible for the expense. By following this approach during the test period, only 18.9 percent of the legal expenses associated with securing copyright and trademark registrations for a gas safety program mascot were assigned to gas operations. [FN147] Likewise, 18.9 percent of the expenses for outside counsel utilized in Case No. 98-426 were allocated to gas operations. [FN148]

The Commission finds that LG&E's approach of allocating all outside legal expenses, regardless of the nature of those expenses, is not only inappropriate for rate-making purposes, but is also inappropriate accounting. LG&E operates two regulated businesses, the provision of electric service and the provision of gas service. Consequently, LG&E should be examining all expenditures to first determine whether the expense can be directly assigned to either the electric or gas operations. Only after concluding that it is not possible to make a direct assignment should LG&E allocate the expense, using a reasonable methodology, to both the electric and gas operations. Therefore, the Commission finds that LG&E should cease its current accounting practice concerning the treatment of outside legal expenses. LG&E should adopt accounting practices that provide for the direct assignment of outside legal expenses to either electric or gas operations, as appropriate. Only after LG&E has determined that an outside legal expense cannot be directly assigned, it should utilize an appropriate allocation methodology and allocate the expense to its electric and gas operations.

Further, the Commission is concerned that LG&E may be treating other types of operating expenses in the same manner as it has the outside legal expenses. We are also concerned that LG&E's affiliation with KU and the 'one utility concept' could result in expenses being inappropriately allocated between the two regulated utilities. Therefore, the Commission's decision concerning the appropriate accounting practice for outside legal expenses is also applicable to any other operating expense of LG&E, as well as to any expenses involving LG&E and KU, and any other LG&E affiliate.

After considering LG&E's inappropriate allocation of all outside legal expenses and the lack of specific information concerning the nature of the transactions with 26 firms, the Commission finds that it cannot establish a reasonable, ongoing level of outside legal expenses to include in rates. For the same reasons, the Commission finds that it cannot determine the reasonableness of the amounts reported as outside legal expense for the test period. Therefore, the Commission will exclude the entire amount recognized as outside legal expenses from the determination of LG&E's gas rates. As discussed previously in this Order, the Commission has recognized the updated allocation rates for operating expenses. The adjustment calculated in conjunction with that decision includes the total company outside legal expenses for the test period. The Commission has calculated the adjustment to remove all outside legal expenses from gas operating expenses, using the updated allocation rates, which results in a reduction of $240,079. [FN149]

Team Incentive Award ('TIA')

[41] In 1999 LG&E's total company TIA was $4,872,652, which is $760,977 greater than the amount included in the 1999 operating expenses. [FN150] LG&E estimates that the impact that the One Utility Program has upon the 1999 TIA is a reduction of $350,000. [FN151] At the hearing an AG witness agreed that the test-period TIA should be adjusted to reflect the actual 1999 expense and the impact of the One Utility Program. To be consistent with the labor adjustments to reflect the post test-period union wage increase and the One Utility Program, LG&E's test-period TIA should be adjusted. The Commission has increased the TIA by $44,305 to reflect a 21 percent allocation, the labor allocation factor, of the net impact.

Depreciation Expenses

[42] LG&E proposes to increase depreciation expense by $80,513 [FN152] to reflect a full year of depreciation expense on 1999 net plant additions in order for the test period to be more representative of ongoing operations. [FN153] The AG's proposal to decrease depreciation expense by $467,195 [FN154] is composed of two items. First, the AG recalculates LG&E's depreciation expense adjustment so that it reflects the 1999 Study. Second, the AG removes depreciation expense on plant funded by customer advances. [FN155]

As previously mentioned, the Commission has recalculated LG&E's depreciation expense adjustment, applying the 1999 Study to the common utility plant and miscellaneous intangible plant, thereby reducing the test-period expense by $167,448.

LG&E completed its last depreciation study in May 1990. The study was based on account balances as of December 31, 1988. As recommended by the study's consultant, LG&E performed a review of the depreciation accrual rates in 1995. [FN156] Given the time that had lapsed since the last complete study, LG&E should strongly consider performing a new depreciation study rather than a review of depreciation accrual rates only as recommended in the May 1990 Study.

Interest Synchronization

[43] LG&E originally proposed to increase its interest expense by $70,520 , which resulted in a decrease to income tax expense of $28,464. [FN157] LG&E applies its weighted cost of debt to the capitalization adjustments for the Job Development Credit, and the African American Venture Capital Fund. According to LG&E, its adjustment reflects the interest synchronization methodology used by the Commission in Case No. 98-426. [FN158]

LG&E re-examined its interest synchronization methodology and determined that it is the methodology proposed by LG&E in Case No. 98-426 and not the interest methodology approved by the Commission. LG&E made a revision to its interest synchronization methodology to reflect applying its weighted cost of debt to the proposed rate base, which results in an increase to interest expense of $2,161,799 [FN159] and a corresponding decrease to income tax expense of $872,556. [FN160]

The Commission has recalculated the interest synchronization adjustment for LG&E. Using the capital structure and weighted cost of debt determined reasonable herein, the Commission determines that interest expense should be increased by $1,871,676, which results in a decrease to income tax expense of $755,455.

Other Interest Expense

LG&E originally proposed to decrease income tax expense by $46,651 [FN161] to reflect the exclusion of other interest expense. [FN162] At the hearing, however, an LG&E witness acknowledged that because of the revision to the interest synchronization methodology, this adjustment should not be made. [FN163] Therefore, the Commission finds that LG&E's adjustment should be denied.

Income Taxes

[44] LG&E originally proposed an increase in income tax expense of $236,606, reflecting the overall impact its adjustments to revenues and expense would have on income tax expense. [FN164] During the course of this proceeding LG&E made revisions to several of its adjustments resulting in a revised increase to income tax expense of $282,427. [FN165]

In a response to a Commission information request, the AG calculated LG&E's pro forma income tax expense by using the test-period actual gas income tax expense as the starting point and then adjusting for three factors: (1) the income tax impact of all of the AG's pro forma revenue and expense adjustments, (2) the interest synchronization deduction, and (3) the removal of all current and deferred income taxes associated with 'prior period income tax adjustments.' The AG proposes a pro forma income tax expense of $1,977,566, which increases test-period income tax expense by $1,184,905. The AG proposes that the Commission use this methodology in its calculation of LG&E's pro forma income tax expense. [FN166]

According to LG&E, the prior year tax adjustment is a yearly, not a non- recurring, event. LG&E argues that the prior year adjustments that are included in test-period income tax expense should remain. For this reason, LG&E contends that the AG's adjustment should be denied. [FN167]

LG&E's reported 1999 income tax expense reflects 12 months of revenue and expenses. If the prior year true ups are included, income tax expense would reflect a period greater than 12 months. For this reason the Commission finds that the AG's methodology excluding the prior period income tax adjustments is reasonable. The Commission has applied the combined federal and state income tax rate of 40.3625 percent to the accepted pro forma adjustment and has eliminated all current and deferred income taxes associated with 'prior period income tax adjustments,' resulting in an increase to income tax expense of $1,586,386. This adjustment is in addition to the interest synchronization adjustment described previously.

Pro Forma Net Operating Income Summary

The adjusted net operating income for LG&E's gas operations is as follows:

Operating Revenues	$65,941,221
Operating Expenses	56,054,929
ADJUSTED GAS NET OPERATING INCOME	$ 9,886,292

RATE OF RETURN

Capital Structure

[45] LG&E proposes an adjusted end-of-test-period capital structure containing 41.09 percent long-term debt, 7.87 percent short-term debt, 6.25 percent preferred stock, and 44.79 percent common equity. [FN168] LG&E decreased its test-period-end, gas operations' preferred stock and increased its common equity by $205,321, the amount of the discount and expense associated with the preferred stock issues. [FN169] As discussed previously in this Order, LG&E has allocated adjustments to JDIC and the Venture Fund on a pro rata basis to all components of capitalization. The AG's and DOD's proposed capital structures were the same as that proposed by LG&E. [FN170]

The Commission agrees with LG&E, the AG, and DOD, and finds LG&E's gas capital structure is as follows:

	Percent
Long-Term Debt	41.09
Short-Term Debt	7.87
Preferred Stock	6.25
Common Equity	44.79
Total Gas Capital	100.00

Cost of Debt and Preferred Stock

[46, 47] LG&E proposes a cost of long-term debt of 5.45 percent and a cost of short-term debt of 6.02 percent. The AG and DOD use the costs of debt proposed by LG&E. [FN171] These rates reflect the cost of debt as of test-period end. [FN172] In addition, LG&E adjusted the cost of long-term debt to reflect the exclusion of debt cost associated with its environmental compliance investment, consistent with the Commission's decision in Case No. 98-426. [FN173] In response to a hearing data request, LG&E provided an update of the cost of long-term debt, short-term debt, and preferred stock as of June 30, 2000.

The Commission finds that it is not appropriate to adjust the cost of long- term debt for LG&E's gas operations to reflect an adjustment that relates solely to its electric operations. The adjustment to the debt cost associated with LG&E's environmental compliance investment relates only to its electric operations. LG&E has offered no compelling evidence to persuade the Commission that the cost of debt applied to its gas operations should reflect an adjustment made for its electric operations.

The Commission also finds it appropriate to recognize the debt cost rates as of June 30, 2000 when determining the overall cost of capital for LG&E's gas operations. The recognition of the updated debt cost rates constitutes a known and measurable adjustment and is more representative of the period the rates established in this Order will be in effect as compared to the test-period-end debt cost rates. However, these debt cost rates will be applied to the test- period-end capital structure. Therefore, the Commission finds the cost of long- term debt to be 5.58 percent and the cost of short-term debt to be 6.75 percent. [FN174]

LG&E, the AG, and DOD all utilized the test-period-end cost of preferred stock rate of 5.19 percent. Consistent with the approach used in determining the cost of debt, the Commission believes it is more appropriate to use the cost of preferred stock as of June 30, 2000, applied to the test-period-end capital structure. Therefore, the Commission finds the cost of preferred stock to be 5.54 percent. [FN175]

Return on Equity

[48, 49] LG&E estimates its required return on equity using four methods: the discounted cash flow ('DCF') method, the capital asset pricing model ('CAPM '), two risk premium analyses, and a comparable earnings analysis. Based on the results of these methods, LG&E recommends a return on equity range of 11.5 to 12.5 percent with a midpoint of 12.0 percent.

The DCF and CAPM analyses were performed using eight electric companies as proxies for LG&E. LG&E proposed the use of proxy companies for the analysis, rather than its stock price, because it is a subsidiary of LG&E Energy. LG&E's stock is not publicly traded. In addition, PowerGen, plc ('PowerGen') is in the process of acquiring LG&E Energy. [FN176] LG&E's criteria for selecting a comparison company was inclusion in Value Line's listing of electric utility companies and a bond rating criterion centered on the current bond ratings of LG&E, which is A1 by Moody's and A+ by Standard & Poor's. [FN177]

In response to a data request, LG&E submitted new cost of equity estimates using a comparison group made up of four gas companies. [FN178] The gas study results are slightly higher than those for the electric group study . The difference in results is attributed mostly to the length of time between the two studies and to slightly higher recent interest rates. Had LG&E relied on the gas study for its recommended return on equity, the result would have been a range of 11.75 to 12.75 percent. [FN179] However, LG&E continued to rely on its electric group study, with a return on equity range of 11.5 to 12.5 percent and a midpoint of 12.0 percent. [FN180]

The AG criticizes LG&E's return on equity estimates on several grounds. The AG contends that LG&E's use of Value Line 'Safety Ratings' is an inappropriate tool to select companies with comparable risks as required by Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944). [FN181] The AG argues there are problems with LG&E's CAPM analyses, specifically claiming that conceptual errors were made in the application of an arithmetic mean versus a geometric mean in calculating expected market premiums. [FN182] The AG also argues that implementation errors were made by mismatching current risk free rates with long-term risk premiums and that the mismatch could have been avoided by applying a current risk premium to the current risk free rates. [FN183]

The AG's analysis differs at a threshold level in that he did not use a similar group of companies as proxies for LG&E in his DCF and CAPM analyses. The AG argues that compliance with Bluefield and Hope drove the selection of four gas companies as proxies, because their gas businesses were more similar to LG&E's than were those of other companies. [FN184] LG&E acknowledged that four of the eight electric companies identified in Rosenberg's Direct Testimony, Schedule 1 (Allegheny, FPL Group, CLECO and Idacorp) are not in the gas distribution business and that four of the eight (CH Energy, Constellation, FPL Group, and GPU) have nuclear generation. LG&E also acknowledged that data from these companies was used in its DCF and CAPM analyses. [FN185]

Responding to the AG's criticisms, LG&E argues that it correctly used an arithmetic mean in its CAPM analysis and provides citations from published sources as additional proof of the correctness of its methods. [FN186] LG&E contends the methods used in its Risk Premium analysis are correct and that the AG's arguments concerning mismatched risk free rates and risk premiums are without merit. [FN187]

The AG estimated a fair rate of return on common equity for LG&E's gas operations using two versions of a DCF analysis, a CAPM analysis and the bond- yield-plus-risk-premium approach ('Bond-Risk-Premium'). The AG's DCF analyses were performed using a comparison group of four publicly traded gas utilities. The AG did not perform a DCF analysis for LG&E's parent, LG&E Energy, for three reasons. First, LG&E Energy is in the process of merging with PowerGen; therefore, the premium offered by PowerGen is reflected in LG&E Energy's current stock price. Second, LG&E Energy's stock price reflects the consolidated operations of the company, including the electric business of LG&E and KU, the 25-year lease of the Big Rivers Electric Corporation's generating assets, and LG&E Capital Corp., the holding company for LG&E Energy's non- utility investments. Third, the revenue increase that is the subject of this proceeding is only related to the gas operations of LG&E. The AG stated that utilizing consolidated electric and gas company data to determine the rate of return for the gas operations alone would not meet the requirements of Bluefield and Hope. [FN188]

The AG selected his comparison group of companies starting with the 34 gas distribution companies listed in the regular and expanded editions of Value Line. All companies that did not have at least 95 percent of their operations in the gas business were eliminated. Next, companies with net plant greater than $900 million were removed because companies of that size would not make a good comparison given LG&E's net gas plant value of $291.45 million. Companies involved in a merger or take-over were also excluded from the comparison group. The last companies eliminated had recently experienced unusual events or were companies for which the necessary forecast information was not available.

The AG's constant-growth DCF analysis produced eight growth rates ranging from 6.85 percent to 13.95 percent. When the AG excluded the two lowest results, which are lower than some bond rates, and the two highest results, the analysis produces a range of 9.5 to 10.5 percent, with a midpoint of 10.0 percent. The AG's two-stage DCF analysis produces a cost of equity of 11.3 percent. His CAPM analysis produces a range of 9.5 to 10.5 percent, with 10.0 percent as the midpoint. The AG's Bond-Yield-Risk-Premium method produces a range of 10.47 to 11.06 percent with 10.77 percent as the midpoint. Based on these analyses, the AG recommends a rate of return on common equity for LG&E of 10.0 percent. [FN189]

LG&E argues that there are several problems with the AG's analysis. LG&E contends that the constant growth DCF method is unreliable, using the AG's own analysis to support this view. LG&E cites the fact that half of the DCF results were eliminated from consideration because they were below bond yields or too high to be relied upon by investors. LG&E argues that the second stage growth used by the AG in the two-stage DCF method understates the estimated growth significantly and therefore casts doubt on the results. LG&E also disagrees with the inputs that the AG uses in his CAPM analysis, stating that because of the inputs utilized, the results understate the required return. LG&E also states that none of the AG's 36 CAPM calculation results falls within the AG's recommended range of 9.5 to 10.5 percent. [FN190] Nine of the results fall below the recent cost of debt while 18 of the estimates are above the CAPM recommended range. LG&E adds that the smaller size of the companies included in the AG's comparison group requires a size premium, thus increasing the AG's calculated cost of equity. LG&E also takes issue with the inputs used in the AG's Risk Premium Analysis. LG&E contends that the AG's use of the Composite Treasury yield reflects the yield on all Treasury bonds with a maturity over 10 years, which differs from the yield on 10-year Treasury bonds alone. LG&E states that use of the Composite Treasury yield understates its cost of equity by 40 basis points. [FN191]

The AG correctly points to several serious problem s regarding LG&E's proxy group of comparison companies. One of the criteria for using a group of companies as a proxy is for that group to resemble as nearly as possible the company in question. The Commission finds it is inappropriate to include electric companies in the proxy group since this case involves only LG&E's gas operations. In addition, some of the electric companies selected have nuclear generation in their portfolios, which further differentiates the proxy group from LG&E's gas operations. Finally, it is likewise inappropriate to include electric companies with no regulated interests in natural gas distribution in the proxy group. For these reasons, the makeup of its proxy group invalidates many of LG&E's cost of equity calculations.

The Commission agrees in part with LG&E's critique of the AG's cost of equity estimates. The AG's DCF estimations are wide-ranging and not all are reasonable enough to be applicable to LG&E's cost of equity. The AG's CAPM analysis also has wide-ranging results, some of which are similar to the low results the AG removes from consideration in his DCF analysis because they are near bond rates. Also, the gas companies included in AG's proxy group are small enough to warrant the addition of a size premium, which is not included in any of the AG's analyses.

After reviewing the evidence of record and considering the infirmities in both LG&E's and the AG's analyses, the Commission finds that a reasonable return on equity falls somewhere between the levels recommended by the parties. A further issue in consideration of an appropriate return on equity is that LG&E's proposed WNA Clause is being approved by this Order. The Commission believes the WNA Clause will work to stabilize revenues over time and decrease the risk to LG&E's shareholders. Based on all these factors, the Commission finds that LG&E's return on equity should fall within a range of 10.75 to 11.75 percent, with a midpoint of 11.25 percent.

Rate of Return Summary

[50] Applying the rates of 5.58 percent for long-term debt, 6.75 percent for short-term debt, 5.54 percent for preferred stock, and 11.25 percent for common equity to the capital structure produces an overall cost of capital of 8.21 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on LG&E's gas rate base of 7.66 percent, which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined, based upon a gas capitalization of $266,376,827 and an overall cost of capital of 8.21 percent, that the net operating income found reasonable for LG&E's gas operations is $21,869,537. LG&E's pro forma net operating income for the test period is $9,886,292. Thus, LG&E needs additional annual operating income of $11,983,245. After the provision for bad debts, the PSC Assessment, and state and federal taxes, there is a revenue deficiency of $20,193,449, which is the amount of additional revenue granted herein. The net operating income found reasonable for LG&E's gas operations will allow it the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth.

The calculation of the overall revenue deficiency is as follows:

Net Operating Income Found Reasonable	$21,869,537
Pro Forma Net Operating Income	9,886,292
Net Operating Income Deficiency	11,983,245
Gross Up Revenue Factor [FN192]	.5934224
Overall Revenue Deficiency	$20,193,449

The additional revenue granted will provide a rate of return on the gas rate base of 7.66 percent and an overall return on total gas capitalization of 8.21 percent. The $20,193,449 increase represents an increase of 7.26 percent over the normalized gross operating revenues. [FN193]

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $299,834,375. The gas operating revenues reflect the most recent gas cost adjustment approved in Case No. 90-158-MM. [FN194]

The Commission notes that it has been nearly 10 years since LG&E's last gas rate case. While LG&E is comprised of the regulated businesses of electric service and gas service, it had not been calculating or monitoring the separate rates of return on rate base and common equity until 1998. [FN195] An analysis prepared by LG&E shows that since 1996 its rates of return on rate base and common equity for gas operations have been decreasing and were at levels that could not be considered reasonable. [FN196] The existence of these low rates of return on gas operations came to the Commission's attention in Case No. 98- 426. In the January 7, 2000 Order in that case, the Commission stated: 'It is the responsibility of LG&E to take the appropriate steps to address that problem by some means other than relying on a subsidy from its electric operations.' [FN197] The present case represents LG&E's response to address its low rates of return on gas operations. LG&E states that it is now monitoring the achieved rates of return for its electric and gas operations separately. [FN198] The Commission expects LG&E to utilize this monitoring as a means to identify when it needs to take corrective action concerning the rates of return for its gas operations. The Commission reemphasizes its concern that one segment of LG&E's operations that is earning an excessive rate of return should not subsidize a segment that is under earning. The customers of the individual gas and electric operations should pay no more or no less than the cost of service. When corrective action is indicated, whether the earned returns are deficient or excessive, the Commission also expects LG&E promptly to initiate the appropriate proceeding to address the situation.

PRICING AND TARIFF ISSUES

Cost-of-Service Study

[51-53] LG&E presented an embedded class cost-of-service study for the 12 months ended December 31, 1999 adjusted for known and measurable changes to the test year operating results. [FN199] The primary objective of a cost-of-service study is to determine the rates of return on a company's investment at present and proposed

rates for each rate class. Generally, LG&E's cost-of-service study indicates that, at present rates, all class rates of return are below reasonably expected returns with the exception of the firm transportation class. [FN200] A cost-of-service study may also be used as a guide in developing an appropriate rate design for each customer class. LG&E used the results of the cost-of-service study to design rates to better achieve a balance in its class rates of return while affording recognition to the marketplace, customer acceptance and gradualism.

LG&E's cost-of-service study incorporates the 'zero-intercept' methodology to classify distribution mains into customer and demand components. [FN201] The theory behind the zero-intercept methodology is that a linear relationship exists between the unit cost of distribution mains and the capacity of the main proportionate to its diameter. Upon establishing this linear relationship, it can be determined, theoretically, where the cost component of mains is invariant to the size of the main. Another methodology LG&E could have employed is the 'minimum system,' but this methodology is generally considered to be more subjective than the zero-intercept approach. As it has stated in numerous orders over the last decade, the Commission believes that the zero- intercept methodology is the more acceptable way to divide distribution main costs into demand-related and customer-related components. Moreover, the Commission is convinced that the zero-intercept methodology is statistically more sound and less subjective than the minimum system method, in which a minimum size main must arbitrarily be chosen in order to determine the customer-related component. As pointed out in KIUC's brief, the minimum system approach would significantly assign greater costs to the residential class and away from other classes. [FN202]

The AG identified a number of problems with LG&E's study, which in his opinion renders the results of the study unusable. [FN203] Therefore, the AG developed an alternative cost-of-service study using LG&E's study and making or substituting proposed solutions for the problems identified.

The first problem identified by the AG was the use of two duplicate allocator names that caused incorrect allocations of selected operating expenses. The second problem was identified as an inappropriate allocation choice for removing promotional advertising expense from the cost-of-service study. The third problem was identified as the appropriate means to allocate forfeited discounts and miscellaneous service revenues. The allocation of customer service expenses was identified as a fourth problem. The last concern identified by the AG was the appropriate way to allocate fixed storage and transportation costs.

In its rebuttal testimony, LG&E agreed with the AG on the duplicate allocator names, the introduction of a better removal of promotional advertising expense, and the more appropriate forfeited discount allocator. [FN204] The remaining issues of fixed storage costs, customer service expenses, and miscellaneous service revenues are discussed below.

[54, 55] Fixed Storage Cost. The issue of the appropriate allocator for fixed storage cost generally revolves around the need to constantly maintain LG&E's gas distribution system in balance within the defined physical tolerances of the industry. In its cost-of-service study, LG&E allocates no fixed storage costs to interruptible transportation customers. As noted by the AG, this is the first LG&E case wherein transportation customers have been served under a tariff that permits transportation services without requiring back-up gas service. The AG contends that to promote equity and fairness among all classes of service, it is necessary to allocate at least a small portion of the fixed storage cost to these interruptible transportation customers. The AG argues that while interruptible customers should not pay as much as firm customers, it is not reasonable that interruptible customers should pay none of the fixed storage costs. The AG further argues that the construction of the storage assets preceded the introduction of the transportation class of service and therefore was intended to serve all classes of service. The AG

proposes an allocation of fixed storage costs with 50 percent based upon the class relationship of annual throughput and 50 percent based upon the class relationship of storage demand. [FN205]

LG&E counters that the interruptible transportation class is served on a firm commitment basis, but only to the extent that deliveries to the system are equal to the volumes consumed, i.e. balanced within the class or the system. In its brief LG&E lists several reasons why it did not allocate fixed storage costs to the transportation and other interruptible classes. [FN206] These include the exclusion of storage services from the tariffs or contracts for this class, the interruptible nature of the service, and the inability to use the storage fields during the spring and summer months due to maintenance and injections [FN207] and due to withdrawals during the winter months. In addition, there are balancing and penalty provisions currently in place for these customers, such as utilization charges, monthly cash-out provisions and operational flow orders that provide LG&E the ability to maintain overall system balance.

The issue of allocating fixed storage cost can be summarized as one of shifting costs to the interruptible transportation customers and special contract customers and away from firm service customers. LG&E cautions that shifting costs to these interruptible customers will likely increase the chance of these customers physically bypassing the distribution system with the consequence that the remaining customers would be required to bear the fixed costs previously borne by the interruptible customers.

Having given consideration to both the arguments and the counter-arguments, the Commission finds that the AG has not offered persuasive evidence that a modified allocation of fixed storage cost based on a weighted analysis of 50 percent storage demand and 50 percent annual throughput is reasonable. We conclude that, while LG&E's approach may not be perfect, its arguments against allocating fixed storage costs to interruptible customers are persuasive and reasonable. Therefore, we accept LG&E's position on the allocation of fixed storage costs.

[56, 57] Customer Service. During his review of the case, the AG noted that in comparison to LG&E's previous gas rate case, the relationship of customer service and sales expenses had dramatically changed.. During his review of the case, the AG noted that in comparison to LG&E's previous gas rate case, the relationship of customer service and sales expenses had dramatically changed. [FN208] Upon a closer examination of these expenditures, the AG surmised that a shift had been made in LG&E's customer service and sales departments to emphasize the efforts necessary to retain and attract large volume customers. In allocating these costs to the various classes, the AG assigned more employees to the commercial and industrial customers than were in fact actually supporting these customer classes. In its rebuttal testimony, LG&E asserts that the AG misinterprets the information provided during the investigation through both undercounting and overcounting. [FN209]

The issue of how to allocate customer service and sales expenses is best described as a shift of costs to commercial and industrial customers and away from residential customers. Having given consideration to both the arguments and the counter-arguments, the Commission is not persuaded that a modified allocation of customer service and sales expenses is needed at this time. The residential class rate of return is still substantially below the system average.

Miscellaneous Service Revenue. The AG proposes to modify the allocation of miscellaneous service revenue on the same basis as that used for forfeited discount revenues. [FN210] The impact of this change is to shift more revenues to residential customers, thus lowering their cost of service. On the other hand, LG&E allocates miscellaneous service revenues based on total sales revenue. LG&E, in response to information requests during the hearing, provided an analysis of items included in the test-year miscellaneous service revenues. [FN211] LG&E's analysis supports the allocation of a greater portion of these revenues to the commercial and industrial classes. LG&E's methodology reflects this allocation; therefore, the Commission finds that the AG's proposed modification should be denied.

Conclusion. The Commission finds the cost-of-service study as modified by LG&E to be reasonable. It provides a means of measuring individual class rates of return and can be used as a guide in developing appropriate revenue allocations and rate design.

Revenue Allocation

[58, 59] LG&E's cost-of-service study reflects a rate of return for the residential class, Rate RGS, considerably below the total company rate of return. [FN212] For this reason, LG&E proposes a larger percentage increase for Rate RGS than for its other rate classes. However, the increase proposed by LG&E for the residential class is less than the increase supported by the results of its cost-of-service study. Its proposed rates, LG&E asserts, establish a reasonable balance between the result of its cost-of-service study and the realities of the current marketplace. LG&E is also proposing increases for commercial and industrial customers served on rate schedules CGS, IGS, and G-6, but it proposes no increase to its special contract customers. According to LG&E, even though its cost-of-service study shows the special contract customer class to have a relatively low rate of return, the pricing for these customers must reflect competitive considerations such as physical by-pass. [FN213]

The AG opposes LG&E's proposed revenue allocation and states that all customer classes should be assigned part of the proposed increase. The AG sponsors an alternative cost-of-service study and argues that it shows that all rate classes fall well short of the 8.40 percent overall rate of return requested by LG&E. [FN214] Although the results of his cost-of-service study support widely varying percentage increases among LG&E's customer classes, the AG proposes relatively equal percentage increases of 4.5 to 6.5 percent for all rate classes except special contracts, which he proposes to increase by 8.4 percent. [FN215] The AG argues that other rate classes should not subsidize special contract customers even if there is a danger of these customers leaving the system. He contends that if special contract customers don't cover their expenses and make a contribution to fixed costs the value of continuing to serve those customers is questionable. [FN216]

In evaluating this issue, the Commission is cognizant of the major changes the natural gas industry has undergone in recent years. As a result of these changes, large volume end-users, mainly industrial customers, have sought out their own gas supplies at prices lower than the local distribution company's ('LDC's') price for its system supply gas. Some of these customers that have large volumes and that are located relatively close to an interstate pipeline may bypass an LDC to avoid paying the LDC for transportation services. The Commission agrees with LG&E on the importance of retaining special contract customers as long as those customers are making a contribution to fixed costs.

LG&E has demonstrated that its **special contract** class is contributing to the system's fixed costs even though the class's rate of return is significantly lower than the total system return proposed by LG&E. As we have found several times in reviewing gas or electric utility **special contracts** or economic development rate proposals, if rates are sufficient to cover **variable costs** plus make a contribution to fixed costs, the system as a whole and the remaining customers benefit. In the absence of the **special contract**/large volume customers' contribution, the remaining customers' rates would require a further increase sufficient to cover those fixed costs. Recognizing that competition, in addition to cost of service, plays a role in revenue allocation, the Commission finds it reasonable to allocate none of the increase awarded herein to the **special contract** class. However, the Commission will continue to monitor LG&E's **special contract** filings and advises LG&E that the prices contained therein will continue to be subject to extensive review.

LG&E proposes to allocate the revenue increase so as to move in the direction of fully allocated cost recovery while minimizing the rate impact for all customer classes. The allocation of the revenue increase granted herein generally follows LG&E's allocation proposal, allowing for the difference between the amount requested and the amount awarded. The rates set out in Appendix A, which increase LG&E's revenues by 7.26 percent, will produce the additional revenues granted herein while generally moving rates toward their actual cost of service.

Rate Design

[60, 61] LG&E proposes to increase its customer charge for residential customers, Rate RGS, from $4.48 to $9.00. To avoid undue disruption for its customers, LG&E proposes to achieve this increase in steps over 3 years, starting with a $7.00 customer charge for the first year following the decision in this proceeding. After one year, the charge would go to $8.00 and then to $9.00 a year later. [FN217] The distribution cost component would also be adjusted downward each year so that the total class revenue remains neutral for the 3 years.

The AG proposes to increase the customer charge by a percentage equal to the overall percentage revenue increase granted LG&E. The AG's recommended revenue increase of approximately 8 percent would produce a customer charge of $4.84. [FN218] The AG and MHNA both point out the adverse impact that rate increases can have on low-income customers.

LG&E also proposes to increase its customer charges for rates CGS and IGS to more accurately reflect the cost to serve the commercial and industrial customers served on those rate schedules. [FN219] The present charge is $8.96 for both rate schedules. LG&E proposes to establish a two-tier customer charge based on meter capacity. Customers with a meter capacity less than 5,000 cubic feet per hour would have a customer charge of $16.50 per month, and those with meter capacity equal to or greater than 5,000 cubic feet per hour would have a customer charge of $117.00 per month. LG&E also proposes to increase its customer charge from $20.00 to $150.00 for Rate G6 customers. [FN220] The AG proposes the same percentage of revenue approach for determining the customer charges for Rate CGS and IGS as he did for rate RGS. The AG did not make a recommendation on LG&E's customer charge proposal for Rate G6.

The Commission believes that a reasonable increase in LG&E's residential customer charge is warranted, given the relatively low level of the current charge and recognizing that it has not been increased for approximately 10 years. However, an increase to $9.00, even using the phased-in approach proposed by LG&E, does not comport with the principles of gradualism and rate continuity. On the other hand, the AG offers no persuasive evidence for limiting the increase to the overall percentage increase in revenues awarded herein. His modified cost-of-service study, when presented in a manner similar to LG&E's cost-of-service study, indicates the residential customer charge should be significantly increased. The AG recommended the Commission rely on the allocation recommendations in the 1989 NARUC Gas Distribution Rate Design Manual. This would result in fewer types of costs being classified as customer- related costs; however, it would also shift costs from the residential class. Such cost shifting is inappropriate given the residential class's consistently low rate of return. After thorough consideration of the issue, the Commission finds that an increase to $7.00 is reasonable as it moves LG&E's customer charge toward the cost to serve its residential customers in a gradual manner.

The Commission finds that the cost justification offered by LG&E in support of the proposed two-tier customer charge for commercial and industrial rate classes is reasonable. We are not persuaded to adopt the AG's percentage of revenue approach for these customer classes any more than we are persuaded to adopt this approach for the residential class. The Commission finds that the proposed customer charges of $16.50 and $117.00 for Rates CGS and IGS are reasonable and appropriate and should be approved. We further find that the proposed charge of $150.00 for Rate G6 is reasonable and should be approved.

WNA Clause

[62] LG&E proposes a WNA Clause applicable to Rate RGS and Rate CGS for an experimental period of three years to adjust for the effects that weather has on its earnings and return on equity. [FN221] The proposed WNA Clause will adjust billing-cycle residential and commercial gas sales for normal temperatures on a real-time basis. LG&E argues that, although a temperature normalization adjustment is historically allowed in rate cases, the absence of a WNA Clause subjects it to drastic fluctuations in earnings and return on equity due to temperature variations. LG&E's mechanism is modeled after Columbia Gas of Kentucky's WNA Clause, which was approved by the Commission in Case No. 97-299. [FN222]

The Commission finds that LG&E's proposed WNA Clause is reasonable and should be approved. We further find that LG&E should be required to file an annual report on the operation of its WNA Clause after each heating season. The annual report shall be filed by June 30th of the summer following the heating season and shall be filed in the format set out in Appendix B to this Order.

Transportation Services Tariff Modifications

[63] Rate TS -- Transportation Service. LG&E proposes to broaden the availability of this tariff to 50 Mcf per day, or 50,000 annually, in order to allow more customers the opportunity to transport their own gas. [FN223] The 'Receipts and Deliveries' section of the tariff will be replaced by a Cash-Out Provision that will more closely control imbalances on the system. LG&E also proposes to make pooling service available under this tariff to correspond to a similar service already available under Tariff FT. [FN224]

Rate FT -- Firm Transportation Service. LG&E proposes to change the manner in which it determines its Cash-Out price to reflect a market based price. LG&E's price will be based on the monthly average of the daily mid-point prices posted in Gas Daily for CNG-South Point for the month during which the imbalance occurred. LG&E states that this change will better reflect the market price at the time the imbalance occurred. LG&E also proposes to modify its penalty for violation of an Operational Flow Order from $15.00 per Mcf to $15.00 per Mcf plus the market price for gas on the day of the OFO. [FN225]

The intervenors do not offer any objection to the proposed tariff changes for either Rate TS or Rate FT. The Commission finds that the proposed changes are reasonable and should be approved.

Line Extensions

LG&E requests Commission approval to reduce the extension of mains to new customers from 100 feet per customer to 80 feet. LG&E failed to justify its request other than claiming savings would result to LG&E if it extends the mains 80 feet in lieu of 100 feet. All the gas utilities in Kentucky provide up to 100 feet of main to new customers, while some provide up to 200 feet. In addition, 807 KAR 5:022, Section 9(16), requires a gas utility to provide up to 100 feet to an existing distribution main without charge for a prospective customer. KRS Chapter 13A does not provide for such cavalier treatment of policies duly promulgated in administrative regulations. LG&E's request to permanently deviate from 807 KAR 5:022, Section 9(16), should be denied.

GAS MAIN REPLACEMENTS

[64, 65] Since 1996, LG&E has been engaged in an extensive gas main replacement project. Between 1996 and 1999, LG&E has replaced approximately 123 miles of its existing mains, and it plans to replace an additional 45 miles during 2000. [FN226] LG&E estimated that the annual cost of this project has been between $8 and $9 million, with the work in 2000 estimated to cost $11 million. [FN227] The capital investment associated with this project has contributed to the erosion of LG&E's earnings from its gas operations during those years.

The Commission commends LG&E for its efforts to maintain and improve the safety and reliability of its gas distribution system. We also encourage LG&E to continue this project, as the safety and reliability of its gas distribution system is of paramount importance. These efforts should provide overall benefits to both its customers and shareholders through enhanced operating efficiencies and lowered costs.

The Commission also recognizes the impact such capital investment has on LG&E's financial condition. When preparing for its next general gas rate case, LG&E may wish to consider filing a historic test period and requesting the recognition of pro forma adjustments for known and measurable changes or filing a fully forecasted test period. [FN228] If LG&E believes some additional measures are needed to address the impact of this capital investment on its earnings, the Commission encourages LG&E to consider and offer well-reasoned proposals to address this issue.

SUMMARY

The Commission, after consideration of all matters of record and being otherwise sufficiently advised, finds that:

1. The rates set forth in Appendix A are the fair, just, and reasonable rates for LG&E to charge for service rendered on and after the date of this Order.

2. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied.

3. LG&E's request to reduce its standard extension of existing distribution main to new customers and to deviate from the requirements of 807 KAR 5:022, Section 9(16), Extension of Services, should be denied.

4. LG&E's proposed WNA Clause is reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A are approved for service rendered by LG&E on and after the date of this Order.

2. The rates proposed by LG&E are denied.

3. LG&E shall, within 30 days of the date of this Order, file its revised tariff sheets setting out the rates approved herein.

4. LG&E's proposed tariff changes to Rates TS and FT are approved.

5. LG&E's proposed WNA Clause is approved, subject to the reporting requirements outlined in Appendix B.

6. LG&E's request to deviate from the requirements of 807 KAR 5:022, Section 9(16), Extension of Services, is denied.

7. As of the date of this Order, LG&E shall cease its current accounting practice concerning the treatment of outside legal expenses. LG&E shall adopt accounting practices that provide for the direct assignment of outside legal expenses to either electric or gas operations, as appropriate. Only after LG&E has determined that an outside legal expense cannot be directly assigned shall it utilize an appropriate allocation methodology and allocate the expense to electric and gas operations. LG&E shall also make this change in accounting practice for any other expense category, as well as expenses involving LG&E and KU or any other LG&E affiliate, that has been previously treated as outside legal expenses.

Done at Frankfort, Kentucky, this 27th day of September, 2000.

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2000-080 DATED SEPTEMBER 27, 2000

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

GAS SERVICE

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through Case No. 90-158-MM.

RGS
Residential Gas Service
RATE:

Customer Charge:	$7.00 Per Delivery Point Per Month	
Charge Per 100 Cubic Feet:		
Distribution Cost Component		13.457 [
Gas Supply Cost Component		54.692 [
Total Charge Per 100 Cubic Feet		68.149 [

Summer Air Conditioning Service Under Gas Rate RGS

RATE:

The rate for 'Summer Air Conditioning Consumption,' as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:	
Distribution Cost Component	8.457 [
Gas Supply Cost Component	54.692 [
Total Charge Per 100 Cubic Feet	63.149 [

CGS Firm Commercial Gas Service

5000 CF/HR $117.00 Per Delivery Point Per Month

RATE:

Customer Charge:		
If all of the Customer's meters have a capacity <5000 CF/HR	$16.50 Per Delivery Point Per Month	
If any of the Customer's meters have a capacity		
Charge Per 100 Cubic Feet:		
On Peak:		
Distribution Cost Component		13.457 [
Gas Supply Cost Component		54.692 [
Total Charge Per 100 Cubic Feet		68.149 [
Off Peak:		
Distribution Cost Component		8.457 [
Gas Supply Cost Component		54.692 [
Total Charge For 100 Cubic Feet		63.149 [

CGS Summer Air Conditioning Service

RATE:

Charge Per 100 Cubic Feet	
Distribution Cost Component	8.457 [
Gas Supply Cost Component	54.692 [
Total Charge For 100 Cubic Feet	63.149 [

CGS Gas Transportation Rider

RATE:
Charge Per 100 Cubic Feet

Distribution Cost Component	13.457 [
Gas Supply Cost Component	54.692 [
Total Charge For 100 Cubic Feet	68.149 [

IGS Firm Industrial Gas Service

5000 CF/HR $117.00 Per Delivery Point Per Month

RATE:
Customer Charge:

If all of the Customer's meters have a capacity <5000 CF/HR	$16.50 Per Delivery Point Per Month	
If any of the Customer's meters have a capacity		
Charge Per 100 Cubic Feet:		
On Peak:		
Distribution Cost Component		13.457 [
Gas Supply Cost Component		54.692 [
Total Charge Per 100 Cubic Feet		68.149 [
Off Peak:		
Distribution Cost Component		8.457 [
Gas Supply Cost Component		54.692 [
Total Charge For 100 Cubic Feet		63.149 [

G-6 Seasonal Off-Peak Gas Rate

RATE:

Customer Charge	$150.00 Per Delivery Point Per Month	
Charge Per 100 Cubic Feet:		
Distribution Cost Component		6.855 [
Gas Supply Cost Component		54.692 [
Total Charge Per 100 Cubic Feet		61.547 [

RATE TS Gas Transportation Service/Standby

RATE:

Administrative Charge	$90.00 Per Delivery Point Per Month		
	CGS	IGS	G-6
Distribution Charge Per Mcf	$1.3801	$1.3801	$.6855
Pipeline Supplier's Demand Component	.6357	.6357	.6357
Total	$2.0158	$2.0158	$1.3212

RATE RBS Reserved Balancing Service

RATE:

Monthly Demand Charges	$5.9900
Monthly Balancing Charges	3.6500
Total	$9.6400

ELECTRIC AND GAS Miscellaneous Service Fees

RATE:

Disconnecting and Reconnecting Service	$18.50
Returned Checks	7.50

APPENDIX B

Louisville Gas and Electric Company shall include the following financial and statistical data in its Annual Report to the Commission on the Weather Normalization Adjustment ('WNA') program:

1. Number of WNA Customers (By Class)
2. Amount of WNA Revenue (By Class)
3. Mcf Volume Adjustment Resulting From WNA (By Class)
4. Average WNA Revenue Per Customer (By Class)
5. Amount of WNA Revenue (Total Company)
6. Mcf Volume Adjustment Resulting From WNA (Total Company)
7. WNA Impact on Earnings for Reporting Period
8. Actual Number of Heating Degree Days
9. Normal Number of Heating Degree Days
10. Variation of Actual Temperatures From Normal Temperatures (%)
11. Number of Customer Inquiries About WNA Program
12. Number of Customer Complaints About WNA Program

APPENDIX C

Determination of LG&E's Gas Operations Capitalization

The determination of LG&E's gas capitalization reflects the allocation of the total company capitalization using a factor based on LG&E's actual test-period gas rate base compared to the total company rate base.

	Gas Rate Base at 12/31/99	Total Co. Rate Base at 12/31/99
Total Utility Plant in Service	$436,334,493	$3,065,838,688
Add:		
Gas Stored Underground	26,664,564	26,664,564
Fuel Inventory	0	17,008,480
Materials and Supplies	1,371,734	33,214,842
Prepayments	244,443	1,566,650
Cash Working Capital Allowance	4,698,540	46,562,526
Subtotal	$ 32,979,281	$ 125,017,062
Deduct:		
Accumulated Depreciation	147,012,854	1,215,031,862
Customer Advances	10,444,203	11,104,354
Accumulated Deferred Taxes	26,462,743	313,854,416
Investment Tax Credit (prior law)	29,222	101,728
Subtotal	$183,949,022	$1,540,092,360
NET ORIGINAL COST RATE BASE	$285,364,752	$1,650,763,390
Percentage of Gas Rate Base to Total Company Rate Base		17.29%

The allocation of Common Utility Plant and associated balances and Prepayments for the gas rate base is consistent with the approach described in the Order. As the allocation only impacts the electric and gas rate base calculations, the total company amounts are not effected.

The balance for Prepayment for both the gas and total company rate bases does not include the PSC Assessment. The balance for Accumulated Deferred Taxes for both the gas and total company rate bases reflects the exclusion of SERP- related deferred taxes. The SERP-related deferred taxes have been found to be a 'below the line' item.

The total company amounts are taken from LG&E's Application, Tab 35, Filing Requirement 6-r, December 1999 Monthly Financial Report, pages 5, 7-10, and 14 and LG&E's Supporting Workpapers filed April 27, 2000, tab 16.

Allocation of Total Company Capitalization to Gas Operations

Component Of Capitalization	Restated Test Period Balances	Total Co. Capital Structure	Test Period Gas Capitalization	Net Capitalization Adjustments	Adjusted Gas Capitalization	Adj. Gas Capital Structure
Long-Term Debt	626,800,000	41.09%	108,373,720	1,068,488	109,442,208	41.09%
Short-Term Debt	120,097,458	7.87%	20,764,850	204,648	20,969,498	7.87%
Preferred Stock	95,327,847	6. 25%	16,482,1-	162,522	16,644,707	6.25%

			85			
Common Equity	683,376,0-17	44.79%	118,155,-713	1,164,7-01	119,320,4-14	44.79%
Total Debt, Preferred Stock, and Common Equity	1,525,601-,322	100.00%	263,776,-468	2,600,3-59	266,376,8-27	100.0-0%
JDIC	67,151,221		2,659,265	(2,659,-265)	0	
Total Capitalization	1,592,752-,543		266,435,-733	(58,906)	266,376,8-27	

The Total Company Restated Test Period Balances reflect LG&E's reclassification of certain stock discount and expense items from Common Equity to Preferred Stock.

Long-Term Debt, Short-Term Debt, Preferred Stock, and Common Equity were allocated to Gas Operations by applying the Gas Rate Base percentage of 17.29% to the Total Company Restated Test Period Balances. Gas JDIC was not allocated using the 17.29% allocation factor, but rather reflects actual gas JDIC plus 23% of LG&E's common JDIC balance.

All Net Capitalization Adjustments were allocated to the components of capitalization on a pro rata basis. The calculation of the Net Capitalization Adjustments is on the following page of this Appendix.

Calculation of Net Capitalization Adjustments

Component Of Capitalization	Other Investments	JDIC	Totals
Long-Term Debt	(24,204)	1,092,692	1,068,488
Short-Term Debt	(4,636)	209,284	204,648
Preferred Stock	(3,682)	166,204	162,522
Common Equity	(26,384)	1,191,085	1,164,701
Totals	(58,906)	2,659,265	2,600,359

Notes:

The Other Investments is made up of LG&E's investment in the African American Venture Capital Fund, which the Commission has treated as a common investment and allocated 23% of the total $256,112, or $58,906, to Gas. This treatment is consistent with the Commission's decision in Case No. 98-426.

The JDIC treatment is consistent with previous Commission decisions.

ORDER

The Commission, upon review of its September 27, 2000 Order, finds that one rate was incorrect. The corrected rate is:

RATE TS
Gas Transportation Service/Standby

RATE:	CGS	IGS	G-6
Distribution Charge Per Mcf	$1.3457	$1.3457	$.6855
Pipeline Supplier's Demand Component	.6357	.6357	.6357
Total	$1.9814	$1.9814	$1.3212

IT IS THEREFORE ORDERED that Appendix A to the September 27, 2000 Order be and hereby is modified to include the corrected rate set forth herein.

Done at Frankfort, Kentucky, this 29th day of September, 2000.

FOOTNOTES

FN1 LG&E generates, transmits, distributes and sells electricity in Jefferson County and in portions of Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer and Trimble counties in Kentucky.

FN2 The percentage increase reflects LG&E's adjusted annual revenues of $192,157,595, based on the gas cost recovery component in its rates effective February 1, 2000. Updating the revenues to reflect the current gas cost component increases the revenues to $279,640,926, which reduces the stated percentage to 9.98 percent.

FN3 Case No. 2000-137, Application of Louisville Gas and Electric Company to Increase its Charges for Disconnecting and Reconnecting Service and for Returned Checks.

FN4 In its order consolidating Case No. 2000-137 and Case No. 2000-080, the Commission ordered the procedural schedule established in Case No. 2000- 080 adopted as the procedural schedule of the consolidated case.

FN5 Transcript of Evidence ('T.E.'), Vol. I, at 82.

FN6 Williams Direct Testimony, Exhibit 2, page 1 of 2, and Exhibit 3, page 1 of 2.

FN7 Case No. 99-176, An Adjustment of the Rates of Delta Natural Gas Company, Inc., Final Order dated December 27, 1999.

FN8 LG&E's Response to the Commission's April 28, 2000 Order, Item 42(a).

FN9 The Commission does not have a 'policy' of using capitalization. The Commission, as it is statutorily mandated to do, reviews each application filed to determine which method more accurately reflects the investment that is used and useful in providing service to the ratepayers.

FN10 Seelye Rebuttal Testimony at 5-6.

FN11 LG&E's Response to the Commission's May 25, 2000 Order, Item 8(c).

FN12 See Seelye Rebuttal Testimony at 3-10 and LG&E's Post-Hearing Brief at 39-44.

FN13 Henkes Direct Testimony at 7.

FN14 Id. at 7-8.

FN15 Case No. 98-426, Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of its Rates and Service, Final Order dated January 7, 2000 and Rehearing Order dated June 1, 2000.

FN16 Henkes Direct Testimony at 9.

FN17 AG's Post-Hearing Brief at 1-2.

FN18 T.E., Volume II, August 3, 2000, at 251-252.

FN19 Case No. 90-158, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, final Order dated December 21, 1990.

FN20 Case No. 99-176, December 27, 1999 Order at 10 and 12.

FN21 Case No. 97-066, An Adjustment of General Rates of Delta Natural Gas Company, Inc., final Order dated December 8, 1997 and rehearing Order dated May 1, 1998.

FN22 Case No. 97-066, December 8, 1997 Order at 7-8. In the May 1, 1998 Rehearing Order, page 2, rate base was revised to $66,751,309.

FN23 Case No. 99-176, December 27, 1999 Order at 3-4.

FN24 LG&E had stated that such a comparison was not relevant to the issue of whether to use rate base or capitalization in calculating revenue increases. See LG&E's Response to the Commission's April 28, 2000 Order, Item 42(b).

FN25 Case No. 98-426, June 1, 2000 Order, at 3.

FN26 See LG&E's Response to the Commission's April 28, 2000 Order, Item 35; and LG&E's Response to the Commission's May 25, 2000 Order, Item 3.

FN27 LG&E's Response to the Commission's May 25, 2000 Order, Item 3(c).

FN28 Rate base of $287,909,011 minus capitalization of $268,202,448 equals $19,706,563.

FN29 LG&E's Response to the Commission's May 25, 2000 Order, Item 3(c).

FN30 LG&E's Response to the Commission's March 15, 2000 Order, Item 35.

FN31 LG&E's Response to the Commission's April 28, 2000 Order, Item 74.

FN32 Id.

FN33 LG&E's Post-Hearing Brief at 5-6.

FN34 LG&E's Response to the Commission's May 25, 2000 Order, Item 24.

FN35 Williams Rebuttal Testimony at 2-4; Seelye Rebuttal Testimony at 11; and LG&E's Post-Hearing Brief at 5-6.

FN36 Seelye Rebuttal Testimony at 12-13.

FN37 Henkes Direct Testimony at 11-13.

FN38 For the specific operating expense accounts impacted and the change in allocation factors, see Williams Rebuttal Testimony at 3 and Williams Rebuttal Exhibit 1.

FN39 Williams Direct Testimony, Exhibit 3, page 1 of 2. In its rebuttal testimony, LG&E revised its calculations and proposed an adjusted gas operations rate base of $287,894,821. See Williams Rebuttal Testimony, Revised Exhibit 3, page 1 of 2.

FN40 Henkes Direct Testimony, Schedule RJH-3. In his brief, the AG revised his calculations and proposed an adjusted gas operations rate base of $277,907,992. See AG's Post-Hearing Brief at 4.

FN41 Prisco Direct Testimony, Exhibit TJP-2. However, the DOD used LG&E's rate base 'for calculation purposes only' and did not advocate either rate base or capitalization to determine the revenue requirements. The DOD revised its calculations to reflect the pro forma adjustments it supported in its direct testimony, and determined an adjusted gas operations rate base of $287,783,447. See Response to the First Data Request of Commission Staff to the DOD, dated July 5, 2000, Items 1 and 2.

FN42 Williams Direct Testimony, Exhibit 3, page 1 of 2. Total gas utility plant in service reflects gas plant in service, gas construction work in progress ('CWIP'), gas stored underground -- noncurrent, 25 percent of common utility plant in service, and 25 percent of common CWIP.

FN43 Henkes Direct Testimony, Schedule RJH-3.

FN44 The following items were included in both LG&E's and the AG's gas prepayment calculations: prepaid insurance, prepaid taxes, prepaid gas franchises, prepaid real estate commissions, and prepaid rights-of-way. See LG&E Supporting Workpapers, filed April 27, 2000, tab 16.

FN45 The Commission has accepted the test-period allocation ratios used for the prepaid insurance and the prepaid gas franchises.

FN46 See Case No. 98-474, The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of its Rates and Service, final Order dated January 7, 2000, at 52 and footnote 134.

FN47 LG&E's Post-Hearing Brief at 10.

FN48 LG&E Supporting Workpapers, filed April 27, 2000, tab 2.

FN49 Henkes Direct Testimony, Schedule RJH-4.

FN50 Id. at 54.

FN51 Seelye Rebuttal Testimony at 27-29.

FN52 The long-term deferred credit balances included in the AG's proposal are related to accumulated Statement of Financial Accounting Standard ('FAS') No. 106 post retirement benefit expense accruals, accumulated internally funded pension expense accruals, FAS No. 112 expense accruals, and workers compensation expense accruals.

FN53 Henkes Direct Testimony at 20-22.

FN54 Seelye Rebuttal Testimony at 14.

FN55 This amount reflects gas ADIT of $21,021,338 and gas ADIT associated with FAS 109 of $5,331,603. See Williams Direct Testimony, Exhibit 3, page 1 of 2.

FN56 This amount reflects gas ADIT of $21,793,472 and gas ADIT associated with FAS 109 of $5,441,680. See Henkes Direct Testimony, Schedules RJH-3 and RJH- 5.

FN57 Henkes Direct Testimony at 14-18.

FN58 Seelye Rebuttal Testimony at 13-14.

FN59 LG&E's Post-Hearing Brief at 7-8.

FN60 Id. at 8-9.

FN61 The SERP exclusion will also be reflected when the Commission determines the rate base ratio to be used to determine LG&E's gas operations capitalization.

FN62 Williams Direct Testimony, Exhibit 2, page 1 of 2.

FN63 AG's Response to the First Data Request of Commission Staff to the AG, dated July 5, 2000, Item 3.

FN64 LG&E had indicated that it considered the common JDIC balance, a credit of $97, to be immaterial and did not allocate a portion of it to gas operations JDIC. See LG&E's Response to the Commission's April 28, 2000 Order, Item 43(d). While this amount is immaterial, it was readily identifiable in LG&E's financial reports. See Application, Tab 35, Filing Requirement 6-r, December 1999 Monthly Financial Report, page 10.

FN65 Williams Direct Testimony, Exhibit 1, page 1 of 2.

FN66 Id. at 2 of 2. Subsequently, LG&E accepted several of the AG's proposed adjustments which increased its adjusted net operating income from gas operations to $8,526,123. See Williams Rebuttal Testimony, Revised Exhibit 1, page 1 of 2.

FN67 Henkes Direct Testimony, Schedule RJH-8.

FN68 Although the DOD proposed an adjustment to LG&E's labor expense, it failed to make a corresponding adjustment to payroll taxes.

FN69 Case No. 2000-137, which was consolidated with this proceeding by Order dated May 19, 2000.

FN70 Kinloch Direct Testimony at 34.

FN71 Valade Direct Testimony at 1.

FN72 Williams Direct Testimony at 8.

FN73 Prisco Direct testimony at 5.

FN74 Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, Final Order dated March 2, 1983.

FN75 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, final Order dated July 1, 1988.

FN76 Williams Direct Testimony at 9.

FN77 AG's Post-Hearing Brief at 10.

FN78 Williams Rebuttal Testimony, Revised Exhibit 1, Schedule G, page 1 of 4.

FN79 LG&E's Response to the AG's Second Request for Information dated May 25, 2000, Item 42, page 3 of 3; and LG&E's Response to the Commission's March 15, 2000 Order, Item 37.

FN80 LG&E's Response to the Commission's May 25, 2000 Order.

FN81 Henkes Direct Testimony, Schedule RJH-16.

FN82 Prisco Direct Testimony at 6.

FN83 Henkes Direct Testimony, Schedule RJH-16.

FN84 AG's Brief at 13.

FN85 Seelye Rebuttal Testimony at 25.

FN86 LG&E's Post-Hearing Brief at 14.

FN87 T.E., Vol. I of III, at 202.

FN88 Id., Vol. II of III, at 177.

FN89 LG&E's Response to the Information Requested During the August 2 through 4, 2000 Hearing, Item 6, page 1 of 2.

FN90 Id., page 2 of 2.

FN91 Williams Direct Testimony at 10.

FN92 Prisco Direct Testimony at 6.

FN93 AG's Post-Hearing Brief at 11.

FN94 See final Order dated January 7, 2000 at 64.

FN95 Williams Direct Testimony, Exhibit 1, Schedule J.

FN96 Id. at 10.

FN97 AG's Post-Hearing Brief at 10.

FN98 Prisco Direct Testimony at 6.

FN99 Seelye Rebuttal Testimony at 21.

FN100 LG&E's Response to Item 5 of the Information Requested During the August 2 through 4, 2000 Hearing.

FN101 Case No. 97-300, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger, final Order dated September 12, 1997.

FN102 Williams Direct Testimony, Exhibit 1, Schedule K.

FN103 Id. at 11.

FN104 Henkes Direct Testimony, Schedule RJH-19.

FN105 Williams Rebuttal Testimony at 6 and 7.

FN106 Id. at 6.

FN107 Williams Rebuttal Testimony at 7.

FN108 AG's Post-Hearing Brief at 16.

FN109 See 807 KAR 5:016, Section 3.

FN110 T. E., Volume I, at 215.

FN111 Id. at 11.

FN112 Seelye Rebuttal Testimony at 22.

FN113 Henkes Direct Testimony, Schedule RJH-14.

FN114 AG's Post-Hearing Brief at 11.

FN115 Prisco Direct Testimony at 6 and 7.

FN116 Id., DOD Exhibit TJP-8.

FN117 LG&E's Response to Item 88(c) of the Commission's April 28, 2000 Order.

FN118 T.E. at 213.

FN119 Williams Direct Testimony at 11.

FN120 Henkes Direct Testimony, Schedule RJH-15.

FN121 Id. at 37.

FN122 LG&E's Post-Hearing Brief at 22.

FN123 LG&E's Updated Response to the Commission's March 15, 2000 Order, Item 38, filed September 1, 2000.

FN124 Henkes Direct Testimony at 45.

FN125 LG&E's Response to Items 9 and 10 of the Information Requested During the August 2 through 4, 2000 Hearing.

FN126 AG's Post-Hearing Brief at 15.

FN127 Id.

FN128 Id. at 27.

FN129 Henkes Direct Testimony, Schedule RJH 20.

FN130 LG&E's Post-Hearing Brief at 22 and 23.

FN131 Id. at 23.

FN132 Williams Rebuttal Testimony at 8.

FN133 AG's Post-Hearing Brief at 17.

FN134 T. E., Volume I at 217.

FN135 Williams Rebuttal Testimony at 4.

FN136 LG&E's Post-Hearing Brief at 25.

FN137 LG&E's Response to the Commission's March 15, 2000 Order, Item 26, lines 2 through 29. The total represents a summation of the amounts shown in column (d) of the response.

FN138 LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 19.

FN139 LG&E's Response to the Commission's March 15, 2000 Order, Item 26, column (h), lines 2 through 29.

FN140 Test period allocations provided in LG&E's Response to the Commission's April 28, 2000 Order, Item 49(c). The determination of the test-period allocation to gas operations is as follows:

Account No. 903024	$3,345 X 44%	=	1,472
Account No. 923100	$1,046,959 X 18.9%	=	197,875
Account No. 925002	$37,299 X 18.9%	=	7,050
Account No. 930208	$161 X 25%	=	40
Total			$206,437

FN141 LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 19.

FN142 LG&E's Post-Hearing Brief at 28.

FN143 AG's Post-Hearing Brief at 19.

FN144 LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 18.

FN145 LG&E states that it expects that it will incur outside legal expenses in 2000 comparable to the amount incurred during the test period. See LG&E's Response to the Commission's May 25, 2000 Order, Item 11(c). The Commission notes that LG&E provided no analysis supporting its statement.

FN146 See LG&E's Response to the Commission's April 28, 2000 Order, Item 49(a); Response to the Commission's May 25, 2000 Order, Item 11(a); and LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 19. The Commission notes that, while not specifically requested, LG&E could have provided copies of the invoices supporting the outside legal expenses when trying to explain the nature of the services provided and how those expenses related to its gas operations.

FN147 Until LG&E provided the information requested at the public hearing, LG&E lead the Commission to believe it had spent $218,874 securing the copyright and trademark registrations. See LG&E's Response to the Commission's April 28, 2000 Order, Item 49(a) and LG&E's Response to the Commission's May 25, 2000 Order, Item 11(a). However, LG&E now states that the total test period expense for this activity was $1,139. See LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 16. LG&E has only provided a general summary of the other additional legal work provided by this firm, with no breakdown of the remaining $217,735. See LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 19.

FN148 LG&E's gas operations were allocated $51,500 related to the representation of LG&E in Case No. 98-426 by outside counsel. While LG&E's amended application in that proceeding contained a proposal to freeze gas rates (a proposal that was rejected by the Commission), Case No. 98-426 dealt only with LG&E's electric operations.

FN149 Using the updated allocation rates provided in Williams Rebuttal Testimony at 3, the determination of the outside legal expense exclusion is as follows:

Account No. 903024	$3,345 X 45%	=	1,505
Account No. 923100	$1,046,959 X 22%	=	230,331
Account No. 925002	$37,299 X 22%	=	8,206
Account No. 930208	$161 X 23%	=	37
Total			$240,079

FN150 LG&E's Response to Item 26(a) of the Commission's May 25, 2000 Order.

FN151 Id. at Item 26(c).

FN152 Williams Direct Testimony, Exhibit 1, Schedule F.

FN153 Id. at 7.

FN154 Henkes Direct Testimony, Schedule RJH-4.

FN155 Id. at 54.

FN156 Application, Tab 31, Filing Requirement 6-R, page S-2, and LG&E's Response to the Commission's April 28, 2000 Order, Item 25(a).

FN157 Williams Direct Testimony, Exhibit 1, Schedule R.

FN158 Id. at 13.

FN159 Williams Rebuttal Testimony, Revised Exhibit 1, Schedule R.

FN160 LG&E's Post-Hearing Brief at 24.

FN161 Williams Direct Testimony, Exhibit 1, Schedule S.

FN162 Id. at 13.

FN163 T.E., Vol. I, at 144.

FN164 Williams Direct Testimony, Exhibit 1, page 2 of 2.

FN165 Williams Rebuttal Testimony, Revised Exhibit 1, page 2 of 2.

FN166 AG's Post-Hearing Brief at 19.

Pro Forma Income Taxes	$ 1,977,566
Less: Actual Income Tax Expense	-890,568
Increase in Income Taxes	$ 1,184,905

FN167 LG&E's Post-Hearing Brief at 26.

FN168 Williams Direct Testimony, Exhibit 2, page 1 of 2.

FN169 Id.

FN170 Henkes Direct Testimony, Schedule RJH-2; Prisco Direct Testimony, DOD Exhibit TJP-9.

FN171 Weaver Testimony, Exhibit Carl G. K. Weaver Schedule 30; Prisco Direct Testimony, DOD Exhibit TJP-9.

FN172 LG&E Supporting Workpapers, filed April 27, 2000, tab 15.

FN173 Case No. 98-426, June 1, 2000 Order, at 4-5.

FN174 LG&E's Response to Information Requested During Hearings Held August 2-4, 2000, filed August 21, 2000, Item 14, page 2 of 2.

FN175 Id.

FN176 Rosenberg Direct Testimony at 7.

FN177 Id.

FN178 LG&E's Response to Item 53(d) of the Commission's Order dated April 28, 2000.

FN179 T.E., Volume I, at 108.

FN180 Rosenberg Rebuttal Testimony at 27.

FN181 Weaver Testimony at 17-19.

FN182 Id. at 43-47.

FN183 Id. at 48.

FN184 Id. at 5-7.

FN185 T.E., Volume I, at 60-62.

FN186 Rosenberg Rebuttal Testimony at 20-23.

FN187 Id. at 25-26.

FN188 Weaver Testimony at 6-7.

FN189 Id. at 41-42.

FN190 Rosenberg Rebuttal Testimony at 8-9. However, referring to Schedule 25 in Weaver Testimony, 6 of the 36 CAPM results do fall within the recommended range.

FN191 Rosenberg Rebuttal Testimony at 14-16.

FN192 The gross up revenue factor recognizes the impact the overall revenue deficiency will have on the provision for bad debts, the PSC Assessment, state income taxes, and federal taxes. The Commission's calculation of the gross up factor follows the same approach as LG&E provided in Williams Direct Testimony, Exhibit 1, Schedule T. The Commission used the same rates as LG&E did, with the exception that the Commission's calculation reflects the most recent PSC Assessment rate of 1.9510.

FN193 The normalized operating revenues reflect the impact of LG&E's most recent gas cost adjustment.

FN194 Case No. 90-158-MM, The Notice of Purchased Gas Adjustment Filing of Louisville Gas and Electric Company, final Order dated July 18, 2000.

FN195 LG&E's Response to the Commission's March 15, 2000 Order, Item 33; and LG&E's Response to the Commission's May 25, 2000 Order, Item 5(b).

FN196 LG&E's Response to the Commission's March 15, 2000 Order, Item 33; and LG&E's Response to the Commission's April 28, 2000 Order, Item 39(c).

FN197 Case No. 98-426, January 7, 2000 Order, at 36.

FN198 LG&E's Response to the Commission's May 25, 2000 Order, Item 5(b).

FN199 Seelye Direct Testimony, Exhibit 1 and 2.

FN200 Seelye Direct Testimony, Table 1.

FN201 Seelye Direct Testimony at 14-17.

FN202 KIUC's Brief at 9.

FN203 Brown Kinloch Direct Testimony at 7.

FN204 Seelye Rebuttal Testimony at 32-48.

FN205 Brown Kinloch Testimony, Exhibit DHBK-3.

FN206 LG&E's Post-Hearing Brief at 46-47.

FN207 T.E., Volume 1, at 301-302.

FN208 Brown Kinloch Direct Testimony at 12-13.

FN209 Seelye Rebuttal Testimony at 40-44.

FN210 Brown Kinloch Testimony at 11.

FN211 LG&E's Response to Information Requested During Hearings, Item 23.

FN212 Seelye Direct Testimony at 19.

FN213 Seelye Direct Testimony at 27.

FN214 Brown Kinloch Direct Testimony at 20.

FN215 Id. at 25.

FN216 Id. at 23.

FN217 Seelye Direct Testimony at 31-34.

FN218 Brown Kinloch Direct Testimony at 32.

FN219 Seelye Direct Testimony at 35.

FN220 Id. at 35-36.

FN221 Seelye Direct Testimony at 37.

FN222 Case No. 97-299, Application of Columbia Gas of Kentucky, Inc., For Authority to Permanently Adopt a Weather Normalization Adjustment Mechanism, final Order dated December 1, 1997.

FN223 Murphy Direct Testimony at 9.

FN224 Id. at 12.

FN225 Id. at 15.

FN226 Farrar Direct Testimony at 5, 11, and 12.

FN227 T. E., Volume I, August 2, 2000, at 39, and LG&E's Response to the Commission's April 28, 2000 Order, Item 19.

FN228 See 807 KAR 5:001, Section 10(7) and (8).

EDITOR'S APPENDIX

PUR Citations in Text

KY.] Re Delta Nat. Gas Co., Inc., 198 PUR4th 132, Case No. 99-176, Dec. 27, 1999.

KY.] Re Louisville Gas & E. Co., 119 PUR4th 431, Case No. 90-158, Dec. 21, 1990.

Ky.] Re Louisville Gas & E. Co., 180 PUR4th 476, Case No. 97-300, Sept. 12, 1997.

U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, P.U.R. 1923D 11, 262 U.S. 679, 67 L.Ed.2d 1176, 48 S.Ct. 675 (1923).

U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 51 PUR (NS) 193, 320 U.S. 591, 88 L.Ed.2d 333, 64 S.Ct. 281 (1944).

END OF DOCUMENT

Re Missouri Gas Energy
Case No. GR-96-285

Missouri Public Service Commission
January 22, 1997

APPEARANCES: Gary W. Duffy, James C. Swearengen, Paul A. Boudreau, and Dean L. Cooper, Brydon, Swearengen & England; P.C., 312 East Capitol Avenue, Post Office Box 456, Jefferson City, Missouri 65102, for Missouri Gas Energy, a division of Southern Union Company. Richard S. Brownlee, III, Hendren & Andrae, 235 East High Street, Post Office Box 1069, Jefferson City, Missouri 65102, for Williams Natural Gas Company. Jeremiah D. Finnegan, Finnegan, Conrad & Peterson, 1209 Penntower Office Center, 3100 Broadway, Kansas City, Missouri 64111, for County of Jackson, Missouri, Central Missouri State University, and University of Missouri-Kansas City. James M. Fischer, Attorney at Law, 101 West McCarty Street, Suite 215, Jefferson City, Missouri 65101, and Susan B. Cunningham, Attorney, Kansas City Power & Light Company, 1201 Walnut Street, Kansas City, Missouri 64106, for Kansas City Power & Light Company. Richard W. French, French & Stewart Law Offices, 1001 East Cherry Street, Suite 302, Columbia, Missouri 65201, and James P. Zakoura, Smithyman & Zakoura, Chartered, 7300 West 110th Street, Overland Park, Kansas 66210, for Mid-Kansas Partnership, and Riverside Pipeline Company, L.P. Mark W. Comley, Newman, Comley & Ruth, P.C., 205 East Capitol Avenue, Post Office Box 537, Jefferson City, Missouri 65102-0537, for City of Kansas City, Missouri. Victor S. Scott, Andereck, Evans, Milne, Peace & Baumhoer, L.L.C., 301 East McCarty Street, Post Office Box 1483, Jefferson City, Missouri 65102-1438, and Richard W. Stavely, Attorney at Law, 257 North Broadway, Suite 200, Wichita, Kansas 657202-2318, for Mountain Iron & Supply Company. Bruce A. Dotson, Bruce A. Dotson Law Firm, 1124 Southwest Main Street, Suite 203, Blue Springs, Missouri 64015-3612, for Gas Service Retirees' Association of Missouri. Stuart W. Conrad, Finnegan, Conrad & Peterson, 1209 Penntower Office Center, 3100 Broadway, Kansas City, Missouri 64111, for Midwest Gas Users Association. Douglas E. Michael, Senior Public Counsel, Office of the Public Counsel, Post Office Box 7800, Jefferson City, Missouri 65102-7800, for the Office of the Public Counsel and the public. Jeffrey A. Keevil, Deputy General Counsel, Penny G. Baker, Deputy General Counsel, Thomas R. Schwarz, Jr., Senior Counsel, and Roger W. Steiner, Assistant General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, for the staff of the Missouri Public Service Commission.

Before Zobrist, chairman, and McClure, Kincheloe, Crumpton, and Drainer, (all concurring), commissioners, and Luckenbill, administrative law judge.

BY THE COMMISSION:

REPORT AND ORDER

Procedural History

***1** On March 1, 1996, Missouri Gas Energy (MGE or Company), a division of Southern Union Company (Southern Union), submitted to the Commission tariff sheets reflecting increased rates for gas service provided to customers in the Missouri service area of the Company. The proposed tariff sheets are designed to produce an annual increase of approximately 13.04 percent ($34,019,650) in the Company's revenues.

On March 8, 1996, the Commission issued an order and notice relating to the tariff sheets. In that order and notice the Commission did not suspend the tariff sheets because they bore an effective date of February 1, 1997.

On March 11, 1996, the Company filed a cover letter accompanied by substitute tariff sheets. The cover letter states that the tariff sheets filed therewith are identical to the tariff sheets filed on March 1, 1996 except for the proposed effective date. The substitute tariff sheets bear a proposed effective date of April 3, 1996.

By order issued March 13, 1996, the Commission suspended these tariffs for a period of 120 days from April 3, 1996 plus an additional six months to February 1, 1997. The Commission also established an intervention deadline of April 8, 1996.

On March 14, 1996, the Office of the Public Counsel (OPC) filed a request for local public hearings with the Commission. On April 19, 1996, OPC filed an amended request for local public hearings with the Commission.

By order issued March 21, 1996, the motion filed by MGE for a protective order was granted. By order issued April 26, 1996, the Commission established a procedural schedule. By order issued May 2, 1996, the Commission established the test year to be the 12-month period ending September 30, 1995, as updated through May 31, 1996.

By order issued on May 3, 1996 the Commission granted the applications to intervene of the following parties: Summit Builders, Inc., JKL Development, Inc./Patterson Peters Development, Inc., Winterset Park, Inc., Patterson and Peters land Company, Inc., Parker-Jones Development, Inc., Longhorn Asset Management, Inc., Jim Robertson Plumbing, Inc., Maple Tree Development, Inc., MDM Development, Inc., Baldwin Properties Inc., Savannah Development, Inc., Terra Land Development Company, Acuff-Lutz homes Inc., Aartic Investments, Inc., Peterson Companies, Cumberland Properties, Inc., and Hunt Midwest Real Estate Development Inc. The Commission ordered that these parties would be denominated as the Kansas City Area Real Estate Developers (Developers) for purposes of this proceeding.

By order issued May 3, 1996, the Commission required Midwest Gas Users Association (MGUA) to file a complete and final list of those entities that intend to participate under the auspices of MGUA and granted intervention to the City of Kansas City, Missouri (Kansas City); County of Jackson, Missouri (JACOMO); University of Missouri-Kansas City (UMKC); Central Missouri State University (CMSU); Local No. 53, International Brotherhood of Electrical Workers, AFL-CIO (Union); Gas Service Retirees' Association of Missouri (GSRA); Williams Natural Gas Company (WNG); Riverside Pipeline Company, L.P. and Mid- Kansas Partnership (Riverside/Mid-Kansas); Kansas City Power & Light Company KCPL); St. Joseph Light & Power Company (SJLP); Mountain Iron & Supply Company (Mountain Iron); UtiliCorp United Inc., d/b/a UtiliCorp Energy Services (UtiliCorp); and MGUA.

***2** By order issued May 9, 1996, the Commission granted the application of the City of St. Joseph, Missouri to participate out of time, without intervention.

By order issued May 24, 1996, the Commission amended the test year to the 12- month period ending March 31, 1996, updated through May 31, 1996.

Pursuant to the order of the Commission, local hearings were convened on August 27, 1996 at St. Joseph, Missouri and Kansas City, Missouri. On August 29, 1996, a local hearing was convened in Joplin, Missouri.

By order issued July 26, 1996, the Commission extended direct testimony relating to issues other than rate design to August 9, 1996, extended direct testimony on rate design to August 19, set rebuttal for September 26-27, and required MGE to provide all response to data requests of the Commission Staff (Staff) and OPC by July 30,

1996.

By order issued August 30, 1996, the Commission directed that a true-up hearing be held on December 12, 1996

By order issued October 15, 1996, the Commission withheld ruling on a motion by OPC to dismiss the case until after the evidentiary hearing. See Section II.A., infra. In the same order, the Commission granted the motion to file supplemental direct testimony filed by the OPC and granted the motion to file supplemental direct testimony and revised schedules filed by the Staff. The Commission held an evidentiary hearing which commenced on October 21, 1996 and continued to October 25, 1996, and reconvened on October 30, 1996 and adjourned on October 31, 1996. On December 12, 1996, the Commission held a true-up hearing in this proceeding.

By order issued November 26, 1996, the Commission denied motions by MGE, the Staff and OPC to extend the dates and limits for the reply brief.

On December 17, 1996, the Commission issued an order regarding a request for outstanding 'uncollectibles' information and amending the procedural schedule in Case No. GC-97-33 (a pending Staff complaint against MGE). In that order the Commission created a project team under the Executive Secretary's office to investigate the practices of MGE related to the use of alleged threatened or actual disconnection to encourage payment from customers. The report from that investigation is to be filed no later than January 31, 1997, in Cases No. GC- 97-33 and GO-95-177. Case No. GO-95-177 is a Staff investigation into the billing practices of MGE.

I. Stipulations and Agreements

A. Stipulation and Agreement Relating to an Experimental Weatherization Program

On October 30, 1996, MGE, the Staff, OPC and the City of Kansas City filed a Stipulation And Agreement in this proceeding relating to an Experimental Weatherization Program. On October 31, 1996, the Commission issued a notice to the parties indicating that they had until November 6, 1996 to indicate whether they objected to the terms of the agreement under 4 CSR 240-2.115. No party has indicated any objection to the agreement.

The agreement provides that the Company will provide $250,000 annually for this program so long as the Commission will include a $250,000 amount specifically for the program in the revenue requirement in this case. The agreement further provides that the program should continue for a period of at least two years from February 1, 1997. MGE's obligation to provide the $250,000 annual payment ceases when that amount is no longer reflected in the rate level authorized by the Commission. The agreement provides that the program funds will be administered by the City of Kansas City, Missouri under a written contract between MGE and the City. MGE and the City will consult with Staff and OPC prior to execution of the contract and its submission to the Commission. While it is experimental, the program will be limited to existing low income (as defined by the Office of Management and Budget (OMB)), MGE residential customers located within Clay, Platte and Jackson Counties, Missouri.

***3** The program is intended to assist customers through conservation, education and weatherization in reducing use of energy and reduce the level of bad debt expense experienced by energy companies.

On January 3, 1997, the parties to the Stipulation And Agreement filed an amendment to it. Under the amendment, the date for the award of contract provided for in paragraph 9 of the proposed tariff is extended from February 1, 1997 until May 1,

1997.

The Commission has reviewed the agreement and the portion of transcript relating to the agreement. The Commission is concerned about this proposal because the revenue requirement impact of $250,000 is spread to all of MGE's customers. The program will directly benefit low income customers in Platte, Clay and Jackson Counties only. Despite the fact that some degree of cross- subsidization occurs under this program, the Commission finds that implementation of the agreement between MGE and the City, with active consultation by OPC, and particularly the Commission's Staff, will be worthwhile insofar as this is an experimental program. However, prior to implementation of a program such as this on a permanent basis, evidence demonstrating that the program benefits all MGE's ratepayers must be produced to justify the revenue requirement impact.

Given the above caveat, the Commission will approve the Stipulation And Agreement (Attachment A) and the amendment thereto (Attachment B).

The Stipulation And Agreement provides that approval thereof disposes of the issues in Case No. GC-96-402. Thus, the Commission will order that Case No. GC-96-402 be closed.

B. Stipulation and Agreement on Cost of Service and Related Revenue Shifts

On October 30, 1996, the Staff, OPC, MGUA, UMKC and JACOMO filed a Stipulation And Agreement relating to cost of service and related revenue shifts. (Attachment C). On October 31, 1996, the Commission issued a notice to the parties indicating that they had until November 6, 1996 to indicate whether they objected to the terms of the agreement under 4 CSR 240-2.115. No party has indicated any objection to the agreement.

If approved by the Commission, this Stipulation And Agreement would resolve issues IV.A.1., Allocation of Costs for Services, Meters and Regulators; IV.A.2., Allocation of Costs for Mains; IV.A.3., Class Cost of Service Results; and VI.B.4., Class Rate Increases. Under the proposed Stipulation And Agreement, if the increase in MGE's revenue requirement in the instant case were $6,096,685, the residential customers would bear $6,054,328 of such increase. (Ex. 159, p. 3, 11. 5-8, Sch. 1). This would mean that residential ratepayers would fund 99.31 percent of the revenue requirement increase. Under the proposed Stipulation And Agreement, if the increase in MGE's revenue requirement in the instant case were $10,096,685, the residential customers would bear $7,983,216 of such increase. (Ex. 159, Sch. 2). This would mean that residential ratepayers would fund 79.07 percent of the revenue requirement increase. Under the proposed Stipulation And Agreement, if the increase in MGE's revenue requirement in the instant case were $15,040,320, the residential customers would bear $10,290,789 of such increase. (Ex. 159, Sch. 2). This would mean that residential ratepayers would fund 68.42 percent of the revenue requirement increase.

***4** This situation occurs because the Stipulation And Agreement calls for a revenue shift to the Residential class. At a revenue requirement increase in the amount of $6,096,685, an amount of $1,788,727 is shifted on to residential ratepayers. The amount of the shift declines as the revenue requirement increases. If the revenue requirement increase is greater than $6,096,685, then the revenue shift to the residential class decreases by one-fifth of the revenue requirement increase above $6,096,685, but not beyond the point where the shift to the residential class becomes zero. The shift to the residential class becomes zero at a revenue requirement increase in the amount of $15,040,320.

The Commission finds that it would be poor public policy to force residential ratepayers to fund more than their previously allocated share of MGE's revenue requirement. The Commission does not understand why the share allocated to residential ratepayers of MGE's total revenue requirement should change with varying revenue requirement results from the instant case.

The Commission shall reject the Stipulation And Agreement and finds that the revenue requirement increase shall be allocated among the customer classes on the same basis as current revenues (i.e., 68.22 percent for Residential; 0.01 percent for Unmetered Gas Lights; 21.22 percent for Small General Service; 2.65 percent for Large General Service; and 7.90 percent for Large Volume Service), as reflected in the compliance filing by Staff on January 17, 1997. The basis of the rejection of the agreement is that no compelling evidence has been produced to justify the residential shift as proposed in the Stipulation And Agreement. In addition, the Commission is not inclined to increase the proportionate share of MGE's revenue requirement borne by residential customers in the face of poor service complaints heard in public testimony. See, infra, IV.5.

II. Pending Motions

A. Motion to Dismiss on Basis that MGE Failed to Comply With Capital Structure Condition in Case No. GM-94-40

On September 27, 1996, Public Counsel filed a motion to dismiss this case on the basis that Southern Union failed to comply with a capital structure requirement to which it had agreed in Case No. GM-94-40. In that case, this Commission approved the acquisition by Southern Union of all Missouri properties previously owned by Western Resources, Inc. (WRI) except for that portion of WRI's system in and around Palmyra, Missouri. The stipulation and agreement entered into by the parties was approved by the Commission and provided:

Southern Union agrees not to implement a general increase in non-gas rates until Southern Union has attained a total debt to total capital ratio which does not exceed Standard and Poor's Corporation's Utility Financial Benchmark ratio for the lowest investment grade investor-owned natural gas distribution company at the time a general rate increase case is filed. Southern Union agrees to attain this total debt to total capital ratio within three years of the closing date of the subject transaction in order to be in compliance with this Unanimous Stipulation and Agreement.

***5** The dispositive issue is whether the trust-originated preferred securities ('TOPrS') issued by Southern Union Financing Company I (SUFI) is to be considered debt or equity. The TOPrS issued by SUFI is backed by a note that Southern Union issued to SUFI. The dividends on the TOPrS can be deferred for a period up to five years. If the dividends are not paid at the end of five years, then the trustee can call the note against Southern Union. The interest paid by Southern Union to SUFI on the note is tax deductible to Southern Union.

The Commission finds that the TOPrS issued by Southern Union Financing Company I constitutes the creation of equity, not debt, with respect to Southern Union. Therefore, Southern Union has demonstrated compliance with the Stipulation And Agreement in GM-94-40, and it is entitled to implement a general rate increase in this case. The Commission finds the Staff's testimony, as well as MGE's testimony, persuasive which shows that Southern Union complied with the intent of the capital structure requirement from GM-94-40. (Ex. 76, p. 28, 1. 14; p. 29, 1. 10).

By its order issued January 7, 1997, the Commission has taken official notice of a press release issued October 21, 1996 by the Federal Reserve Board and the public contents of an internal Federal Reserve Board memorandum dealing with preferred shares of this type. (Attachment D). The press release announced that the Federal Reserve Board has allowed bank holding companies to treat these kinds of preferred securities as equity, and the memorandum sets forth the technical reasons supporting the decision.

On January 14, 1997, OPC filed an Objection And Response To Order Taking Official Notice Of Documents, arguing that the Commission erred by taking official notice of the press release and the memorandum. On January 17, 1997, MGE filed a reply to OPC's objection.

The Commission did not err by taking official notice of the Federal Reserve Board documents. First, these are public records. Second, the treatment of the TOPrS securities as debt or equity is a technical matter within the Commission's specialized knowledge, and the Commission is empowered by statute to determine financial issues of the companies it regulates. See Section 393.200, R.S.Mo. (1994). Third, the Commission gave parties a reasonable opportunity to show that taking notice of the documents would not be proper. Even without considering the Federal Reserve documents, the Commission would have reached the same conclusion based on Staff's and MGE's testimony in this proceeding.

B. MGE's Motion For Variance From Protective Order

On October 17, 1996 MGE filed a Motion For Variance From Protective Order. MGE states that certain requests were made of MGE at the local public hearings in this proceeding to provide additional information regarding some of the customers who testified at the local public hearings. MGE states that it does not wish to send customer-specific highly confidential information to other parties, since the customers involved did not indicate that they wanted the details of their bills distributed to other parties. MGE requests a waiver from the terms of the protective order which would allow it to refrain from providing copies of the highly confidential portion of the summary report to the other parties in this proceeding. The Commission finds that MGE's motion is reasonable and will grant it.

***6** C. MGE's Motion For Admission of Supplement to Exhibit

On January 3, 1997, MGE filed a motion for admission of a Supplement to Exhibit 111. The Supplement relates to testimony given at local public hearings. No party has filed a response to the motion.

The Commission finds that the motion is reasonable and will order that the Supplement to Exhibit 111 be received into the record.

D. MGE's Motion For Admission of Revised True-Up Reconciliation

On January 6, 1997, MGE filed a Motion For Admission Of Late-Filed Exhibit. MGE attached a revised reconciliation dated January 3, 1997 to the motion. MGE recites the fact that there have been unreconciled revenue differences existing at the evidentiary hearing in October, 1996, and at the true-up hearing in December, 1996. MGE states that it believes it has located the source of the discrepancy. MGE suggests that it supplied certain erroneous information in responding to a data request regarding bills and usage in the Small General Service class.

On January 7, 1997, Staff filed a response to MGE's motion, requesting that the Commission deny MGE's motion on the basis that to grant it would be the same as reopening the record and this would violate 4 CSR 240-2.110(10).

On January 9, 1997, OPC filed a response to MGE's motion. OPC concurs with Staff that it is too late in the proceeding to admit MGE's revised reconciliation.

On January 10, 1997, MGE filed a reply to Staff and OPC. MGE requests that the Commission order Staff to perform an expedited audit on the new MGE material to determine its accuracy.

On January 10, 1997, Staff filed a revenue requirement scenario. General note no. 3 states that if the Commission accepts MGE's position on the unreconciled difference matter, then the revenue requirement calculations are correct as shown.

The Commission will deny MGE's motion and not allow the revised true-up reconciliation into the record at this late stage in this proceeding.

III. Late-filed Exhibits

Exhibits 113, 114, 115, 116, 117, 120, 163, 163HC, 164, 171, 172, 173, 174, 179 and 179HC were filed after the close of the evidentiary hearing in this case. These were filed at the direction of the bench. Counsel were afforded a ten-day period in which to file an objection to the admission of these exhibits.

On December 2, 1996, Riverside/Mid-Kansas filed a motion to strike a portion of late-filed Exhibit 172. Riverside/Mid-Kansas requests that the portion beginning with page 3, line 7, through the bottom of page 4, be stricken, because it goes beyond the information requested by Commissioner Crumpton.

On December 10, 1996, MGE filed a response to the motion to strike. MGE argues that all of late-filed Exhibit 172 is responsive to Commissioner Crumpton's request.

The Commission finds that all of Exhibit 172 is responsive to Commissioner Crumpton's request. The Commission will deny the motion to strike.

The Commission has received no objections to the receipt of the late-filed exhibits other than the objection of Riverside/Mid-Kansas discussed above.

***7** Late-filed Exhibits 113, 114, 115, 116, 117, 120, 163, 163HC, 164, 171, 172, 173, 174, 179 and 179HC shall be received into the record.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact.

I. Revenue Adjustments

A. Weather Normalization Adjustment

This issue concerns the appropriate period of time to use for the purpose of establishing 'normal' temperatures in the context of setting rates for MGE. MGE advocates the use of ten years of data ending March 31, 1996. Staff advocates the use of 30 years of data (1961 through 1990). Public Counsel agrees with the Staff on this issue.

MGE witness Cummings maintains that the ten-year average of Heating Degree Days (HDD) compiled by the National Oceanographic and Atmospheric Administration (NOAA) better reflects the temperatures experienced in recent years and is not influenced by several consecutive cold winters which occurred many years ago and have not repeated themselves. (Ex. 9, p. 8). Dr. Cummings performed an analysis where he calculated the median temperatures over the last ten and fifteen years and he concluded that the ten-year measure is more representative of recent years' temperatures than the use of the 1961-1990 measure. (Ex. 9, p. 9). The reason for this result is that there were some winters with extremely cold temperatures a number of years ago that are reflected in the 30-year measure, and these extremes have not repeated themselves in the last decade. (Ex. 9. p. 10).

Staff maintains that the Commission should use the 30-year measure of normal temperatures published by NOAA, which are based on properly adjusted monthly Heating Degree Day data from the FAA weather stations at Kansas City International Airport and the Joplin Airport. Staff argues that the 30-year average is the more proper measure of 'normal weather' rather than the ten-year moving average proposed by the Company. NOAA's 30-year normal averages are compiled independently of the regulatory process and are set for a period of ten years at a time after each decade of data can be analyzed. The calculations of 'normals' are done only once every ten years because they require a substantial effort and commitment of NOAA's resources. The published normals used by Staff remain the same for those ten years until another decade's worth of data is collected and analyzed by NOAA.

Staff believes that the 30-year period utilized by NOAA is necessary to constitute a normal period. This period is long enough to compensate for shorter-term cycles that may be present in the data, while not being so long that historical conditions which are no longer relevant might influence the calculations of normals. Staff maintains that the use of a ten-year moving average as proposed by MGE results in great fluctuations of 'normals' which has no place in setting rates on a forward-looking basis.

***8** The Commission finds that NOAA's 30-year normals is the more appropriate benchmark. The ten-year moving average would needlessly cause frequent rate changes based on the introduction of new data every year. If one takes MGE's argument to its logical extreme, the Commission would use the most recent year's experience in MGE's service territory and re-set rates each year. This could lead to serious financial problems for MGE if its rates were set after a record-setting cold year. In addition, the data upon which Staff's recommendation is based has gone through the processes established by NOAA to ensure the best data possible. This safeguard is not present in MGE's approach.

B. Economic Development Discounts

OPC maintains that the Commission must impute the full level of revenues based on the Large Volume contract rate. OPC bases this position on the tariff language contained on MGE's Sheet 74, which states:

> Prior to any determination of the Company's revenue requirement for rate making purposes before the Commission, test year revenues shall first be adjusted to the level corresponding to that which would be produced under the standard Large Volume contract rate schedule with respect to the customers qualified for service hereunder.

OPC maintains that this language precludes Staff and MGE from making their recommended adjustment that has the effect of having ratepayers fund approximately 25 percent of the amount of economic development discounts.

This issue is the extent to which MGE's shareholders should bear the cost associated with discounted rates which MGE offers under MGE's economic development rider. The cost associated with discounted rates means the amount of revenue forgone by MGE by not charging the full tariffed rate, assuming that the customer would have had the same usage even if MGE had charged the full tariffed rate. In this particular matter, MGE has agreed with Staff that the shareholders will absorb approximately 75 percent of the cost, leaving about 25 percent or $9,500 to be borne by the ratepayers.

The Commission finds that the language of Tariff Sheet 74 does not preclude such an adjustment to test year revenues after those revenues are adjusted to the standard large volume contract rate. The Commission finds that test year revenues in this rate case should reflect the assumption by Southern Union's shareholders of 75 percent of the forgone revenue resulting from discounts from the maximum tariffed rate for customers served under the economic development rider. Given the economic benefits which accrue to the customer base as a whole, it is proper for the ratepayers to shoulder 25 percent of the forgone revenue resulting from discounts from the maximum tariffed rate for customers served under the economic development rider.

C. Delayed Payment Revenue

Delayed payment revenue is the amount of revenue collected by MGE as a result of some customers not paying their bills on time and incurring the two percent late payment fee. The issue appears to be whether the Commission should assume a direct relationship between the authorized revenue requirement and delayed payment revenue.

***9** MGE's position is that there is a direct relationship between the revenue requirement and delayed payment revenue. The Staff's position is that no such direct relationship exists. The Commission finds that MGE has met its burden of proof on this issue. The Commission finds MGE witness Cummings' testimony to be particularly persuasive on this point. Dr. Cummings testified in rebuttal testimony:

Once the authorized overall revenue increase is determined, 0.3098 percent of the authorized increase should be presumed to be recovered through delayed payment revenue, thus serving as an offset to the amount that must be recovered through base rates. The rate of 0.3098 percent is the portion of the Company's revenue that was derived from late payment charges for the year ending March 31, 1996. For example, if a $30 million revenue increase is authorized, monthly base rates should be designed to recover $29,907,060, or 99.6902 percent of the authorized total revenue increase. (Ex. 9, pp. 3-4).

The Staff has not submitted persuasive testimony to counter the proposition that delayed payment revenue would remain a constant 0.3098 percent of the Company's revenue. Therefore, the Commission finds that MGE's position is correct on this issue.

D. Flex Revenue

Staff and OPC have recommended an adjustment of $97,543 which represents the difference between the full-tariffed rate and the actual decreased or 'flex' rates charged to seven customers to provide natural gas service. MGE requests that the ratepayers pay for the difference, arguing that keeping these seven large-volume customers as revenue contributors benefits all ratepayers. If the Commission found in favor of Staff and OPC on this issue, the effect would be to force the shareholders of MGE to fund the 'discounts' provided to these customers.

MGE's tariff provides:

The Company may from time to time at its sole discretion reduce its charge for transportation service by any amount down to the minimum transportation charge for customers who have alternative energy sources, which on an equivalent BTU basis, can be shown to be less than the sum of the Company's transportation rate and the cost of natural gas available to the customer. Such reductions will only be permitted if, in the Company's sole discretion, they are necessary to retain or expand services to an existing customer, to re- establish service to a previous customer or to acquire new customers. The Company will reduce its transportation rate on a case by case basis only after the customer demonstrates to the Company's satisfaction that a feasible alternative energy source exists. If the Company reduces its transportation charge hereunder, it may, unless otherwise provided for by contract upon 2 days notice to the customer, further adjust that price within the rates set forth above.

This language makes it clear that MGE has the authority to flex down charges for certain customers but the tariff does not affect ratemaking treatment.

***10** The Commission recognized the regulatory problem inherent with 'flex' provisions in its decision in Case No. GR-95-160. In that case, the Commission stated:

The Commission is fully aware of the obstacles faced by the natural gas utility industry in a post-636 competitive environment. In order to provide a reasonable opportunity to respond to competitive pressure, within the bounds of the regulatory structure, the Commission will reject the tariff proposal of the Staff and allow United Cities to file a substitute tariff in accordance with the following standards. The Commission will allow United Cities to negotiate and perform transportation contracts with rate flex sufficient to retain economically worthwhile customers on the system, without causing subsidization by the remainder of the ratepayers. United Cities may flex its tariffed transportation rate to meet competition, but must recover all variable costs plus a reasonable contribution to its fixed costs during the course of the contract. United Cities executes and performs under such contracts at its own risk. All transportation contracts will be thoroughly examined and reviewed in any subsequent rate case or PGA/ACA proceeding to determine whether the contract meets the above standard. United Cities will be expected to show substantial and competitive evidence of imminent by-pass by the transportation customer and will, in addition, be required to show that the contracted rate satisfies the requirement to collect no less than the variable costs attributable to the particular transportation customer plus reasonable contribution. The Commission would emphasize that transactions involving non- regulated affiliates will be scrupulously reviewed for determination as to whether all parties acted at arms [sic] length, and rates were flexed down no further than required to meet the relevant competition. Comparison of the affiliates' contract terms with terms contemporaneously available in the market will be probative of the arms [sic] length nature of actions. The Commission's review will be conducted with the understanding that the Company bears the burden of proof with regard to the prudency [sic] of its actions and that inappropriate transactions will result in the imputation of revenue to United Cities. The Commission would not that, upon prima facie showing by another party that a transportation contract was flexed down below the full tariffed rate, United Cities will be required to show by full, complete, substantial and competent evidence that the arrangement 1) was necessary to avoid imminent bypass, 2) recovers variable costs plus a reasonable contribution to fixed costs, and 3) in instances involving affiliates, was at arms [sic] length and flexes rates no lower than necessary to meet relevant competition.

The Commission will apply this standard to MGE in future rate cases. The Commission will clarify, however, that the avoidance of 'imminent by-pass' includes the loss of a customer because of a competitive alternative.

***11** The facts of the current case present a difficult decision to the Commission. On the one hand, MGE has no current information showing an analysis of why it was necessary to flex down in order to retain these seven customers on the system. On the other hand, Staff has assumed that these seven customers would remain on MGE's system and pay the full tariffed rate and consume the same amount of gas if MGE had charged the full tariffed rate. MGE bears the burden to prove that its proposed rate increase is justified. However, the Staff is trying to apply a standard to MGE previously unknown to it. Given these facts the Commission will order that the revenue requirement set in this case reflect 50 percent of the proposed adjustment. Since 100 percent of the proposed adjustment is $97,543, the Commission will order an adjustment of $48,771.50. This will result in shareholders and ratepayers sharing equally the forgone revenue that would have been collected from the seven customers on an equal basis.

In its next rate case, MGE should provide a current analysis of why it was necessary to flex down to retain the customers. Staff should review that analysis and make its own determination of whether the flexdown was necessary to retain the customers. Staff should also verify that the flexdown arrangement recovers the variable costs associated with serving the customers along with a reasonable contribution to fixed costs.

E. Other Revenue Adjustments

It appears from the hearing memorandum that the Commission's decision on issue I.A. (Weather Normalization) will resolve this category.

II. Expense Adjustments

A. Starting Point

The briefs are silent on this matter. The hearing memorandum and MGE testimony state that MGE accepts the expenses included in Staff's September 13, 1996 accounting run as its starting point for purposes of updating the Company's initial filing to the Commission ordered test year in this case. (Ex. 52, p. 3).

The Commission does not discern a contested issue based on the hearing memorandum and briefs.

B. Payroll

The hearing memorandum states that the Staff believes this is no longer a contested issue.

C. Payroll Taxes

The hearing memorandum states that the Staff believes this is no longer a contested issue.

D. Pensions and Benefits

1. Medical Costs -- Active Employees

The hearing memorandum states that MGE accepts Staff's pro forma expense based on actual claims paid, as corrected based on the update to Staff Data Request No. 285. (Ex. 34, pp. 8-9, Ex. 35, pp. 17-22). Thus, there does not appear to be a controversy regarding this issue.

2. Medical Costs -- Retirees

a. Recognition of Gains and Losses

The parties disagree regarding the appropriate method for amortizing actuarial gains and losses with respect to pension and postretirement benefits other than pensions (OPEBs) under Financial Accounting Standards 106 (FAS 106) and 87 (FAS 87). Although this is an issue of first impression for the Commission, the Commission has approved three settlements where the treatment recommended by Staff in this proceeding was used. [FN1]

***12** The Staff recommends that gains and losses under FAS 87 and FAS 106 be amortized to expense over five years. MGE advocates use of a 'corridor' approach, where up to 10 percent of the unrecognized net gain/loss balance is ignored (not amortized) in calculating FAS 87 and FAS 106.

The Commission finds that MGE should recognize gains or losses in its pension and OPEB accounts, and amortize those gains/losses over five years. The Commission does not accept the corridor approach recommended by MGE. The Commission finds MGE's 'consistency' argument not persuasive since the recommendations of Staff and MGE are each allowed by the Financial Accounting Standards Board, and since this Commission has never addressed this issue before for any utility and certainly not for MGE, it is absurd for MGE to argue that rejection of its position would be inconsistent. In fact, adoption of MGE's position would be inconsistent with the treatment of other Missouri utilities. In addition, although Section 386.315, R.S.Mo. relates to the Commission's treatment of FAS 87 and FAS 106 expenses, the statute does not require that the Commission give utilities the most liberal ratemaking treatment possible and adopt the most anti-ratepayer construction of the Financial Accounting Standards. As pointed out by the Staff, MGE does not have the competitive price pressures of other firms that must abide by the FAS standards. MGE, so far, enjoys the benefit of a monopoly for the provision of natural gas service to a large area of Missouri. MGE's attempt to shield the gains in its pension investments by use of the corridor approach is not warranted, and Staff's position will be adopted.

b. COLI Amortization

The Commission approved MGE's use of a COLI program to fund a portion of its OPEB costs in docket GO-94-255. (3 MPSC3d 203 (1994)). The COLI program provided a method of financing OPEB costs based on combining the growth in value of whole-life insurance policies on employees, loans against such policies, and deduction of interest on such loans for income tax purposes. The federal government has now ended the income tax deductions for these programs, which eliminates their viability as a funding mechanism for OPEB expenses.

The Staff and MGE agree that the program should be concluded. MGE proposes to amortize these costs to rates over a three-year period, and to accumulate interest on the unamortized balance, for an annual expense of $465,924. (Ex. 37, p. 3).

OPC contends that the COLI costs should be amortized over 197 months to be consistent with the historical treatment of COLI as part of the FAS 106 cost. (Tr. 182, 11. 10-17). This would result in the amortized expense related to COLI at an annual level of no more than $133,000 rather than the $466,000 proposed by MGE. (Ex. 44, p. 16, 11. 13-16).

Staff proposes that this expense should be amortized over a period of five years, for an annual expense of $249,274. Staff maintains that its proposal is consistent with typical PSC treatment for other unanticipated events, for which accounting authority orders are granted. Staff maintains that the elimination of the tax provisions which drove COLI is an unanticipated event and should be treated like any such similar occurrence. Staff maintains that a five-year amortization without accrual of interest adequately balances between the ratepayers and the shareholders the unanticipated expense of concluding the COLI program.

***13** The Commission finds that it is reasonable for the expenses related to the conclusion of the COLI program to be amortized over a five-year period as recommended by Staff.

3. Pensions

MGE and Staff differ on whether to use the 'corridor' approach for unrecognized pension plan losses or to amortize them over five years. MGE proposes the corridor approach while the Staff recommends a five-year amortization.

For the reasons stated above in Section II.D.2., the Commission finds Staff's position to be the most reasonable.

4. Long Term Disability

MGE decided to not pursue this issue. (Tr. 166).

E. Injuries and Damages

This issue involves determining the level of workers' compensation, automobile liability and general liability expense for the purpose of establishing MGE's rates. MGE's position is that the test year expense level should include the total amount of losses which have been incurred by it. This amount includes not only paid losses, but also amounts which MGE has accrued to pay losses which have occurred, but for which payment is yet to be made. MGE witness Wilson testifies that the 'vast majority' of such claims are known and the total amount of the loss payments are measurable. Using historical loss experience, MGE believes it can reliably determine the losses for the coming year. (Ex. 46, pp. 7-8).

MGE's approach to this issue is not tenable because it would include paid losses, as well as incurred but not paid losses. MGE's proposal is also not appropriate is because it assumes that WRI's experience is valid for estimating MGE's likely experience. The Commission is not inclined to assume that WRI and MGE are so similar that WRI's expense experience should affect the level of injuries and damages expenses for MGE. Also, MGE relies on Southern Union's loss history from Texas in estimating the level of losses MGE will have in Missouri. The reliance on this data is not appropriate because loss experience is influenced by the legal system in various states and, for natural gas companies, the level of activity in the area of safety line replacements.

The Commission finds that the approach utilized by Staff is the most reasonable one presented because it relies on the actual historical experience of MGE while operating in the State of Missouri.

F. Fleet Leases

Based on the true-up reconciliations (Exhibits 177 and 178), the Commission determines that the parties have resolved this issue.

G. Reorganization Costs

MGE proposes that the costs of the permanent elimination of employee positions be amortized over three years. MGE maintains that ratepayers will experience a benefit by the elimination of these employee positions because payroll expense has been reduced in this case. (Ex. 34, p. 10; Ex. 52, p. 7).

Staff is opposed to increasing cost of service for a three-year amortization of severance packages given to employees terminated through a corporate reorganization, because this treatment would constitute retroactive ratemaking and Southern Union's shareholders have already been compensated through reduced payroll expenditures resulting from the terminations. (Ex. 26, p. 2).

***14** OPC maintains that MGE's three-year amortization of severance payments incurred to reduce the number of employees should be eliminated from the prospective cost of service because MGE has already recovered these costs from the savings resulting from the reduction in the number of employees. In fact, OPC's evidence shows that the savings to MGE from the time the severance occurred to the time the rates in this case go into effect are greater than the accrued costs of the severance. (Ex. 42, pp. 23-25).

The Commission finds that MGE's position is based upon fallacious reasoning. It is appropriate that prospective rates will be set on recently available payroll expense. MGE overlooks the substantial cash flow savings that it has achieved by terminating the employees. OPC's evidence shows that Southern Union's shareholders have already received more than the severance costs in terms of reduced payroll. The rates that MGE has been charging are premised on a payroll level higher than that which it currently has, so it has profited by the decreased number of employees.

MGE's position would have the Commission assume that minimization of payroll is the paramount goal of providing utility service. This assumption is wrong. It is essential that MGE provide the best possible utility service per dollar spent by ratepayers. As with any business there is a marginal benefit to ratepayers for the last dollar spent to provide service. The Commission has not seen evidence in this proceeding to suggest that MGE has achieved a proper balance between marginal costs and marginal revenues for the ratepayers of Missouri.

The Commission finds that MGE's shareholders have already received monetary compensation through the reduction in payroll expense. The Commission will not allow MGE to charge ratepayers the costs associated with employee severances where MGE has already recovered those costs.

The Commission finds that the position of Staff and OPC is most reasonable on this issue.

H. Advertising

Staff and MGE are in agreement regarding the amount of advertising expenditures made by MGE to be included in rates. However, OPC believes more of the advertising expenses incurred by MGE during the test year should be excluded from rates. Specifically, Staff and MGE agree that $16,629 of MGE's advertising expenses should be excluded from rates, but OPC believes that $48,074 should be excluded, a difference of $31,445. (Ex. 174).

The controversial advertising expenditures are broken into six distinct groups by OPC. The first item for which OPC proposes disallowance are charges from Smith

Grieves & Company relating to billing inserts for the Neighbors Helping Neighbors Program. OPC classified this advertisement as institutional and proposes disallowance of $4,957.69 of associated cost.

MGE argues that the Neighbors Helping Neighbors program provides a direct benefit to ratepayers and thus, should be allowed in rates.

The Commission finds that the advertising costs associated with the Neighbors Helping Neighbors program should be allowed in rates. With cutbacks of federal funding to help low income users of natural gas programs like Neighbors Helping Neighbors are increasingly important. Because it is in the interest of all ratepayers generally to assist low income users of natural gas, the Commission will allow gas utilities to pass through a reasonable level of costs to the ratepayers to subsidize the existence of programs designed to benefit low income users of natural gas.

***15** The second item for which OPC recommends disallowance is a duplicate charge from Smith Grieves & Company in the amount of $4,546.57. Staff failed to remove this duplicate charge but Staff witness O'Keefe, during cross- examination, admitted that the duplicate charge should be removed. (Tr. 304, 11. 2-18).

The Commission finds that the revenue requirement set in this case should reflect removal of the duplicate charge in the amount of $4,546.57 from Smith Grieves & Company.

The third item for which OPC recommends disallowance is the cost of advertising for the public relations manager in the amount of $833.45. The Commission finds that such cost should be allowed in rates because this position is no longer in the Community Relations Department. (Tr. 319).

The fourth item for which OPC recommends disallowance is the cost of brochures, folders, brochure holders and laser sheets from TNT, Inc. in the amount of $16,862.93. OPC recommends disallowance of seven-eighths of the TNT, Inc. costs because seven of the advertisements were promotional in nature, while one related to safety. (Ex. 55, p. 25, 11. 25-30).

Staff had excluded four-fifths of the TNT, Inc. advertisements and left in the cost of service the advertisement holders. (Ex. 55, p. 25. 11 22-25). However, during cross-examination, Staff witness O'Keefe stated that OPC's proposed seven-eighths adjustment was correct and should be adopted. (Tr. 308, 11. 3-8).

The Commission finds in favor of OPC on this issue because seven-eighths of the cost of brochures, folders, brochure holders and laser sheets from TNT, Inc. are promotional in nature.

OPC recommends a disallowance in the amount of $5,035.57 which reflects the cost associated with various advertisements for the Missouri Restaurant Association, the Home Builders Association, the purchase of promotional t- shirts, the cost of printing and shipping pocket calendars embossed with MGE's name, and charges for 300 reprints of 'Cooking for Profit.' OPC contends that all of these advertisements seek to encourage the use of natural gas or enhance MGE's corporate image.

The Commission finds that the $5,035.57 amount should not be allowed in rates because these expenses are incurred to encourage use of gas over electricity or to promote MGE's corporate image. The Commission has to consider the energy market in making these decisions. The Commission will not encourage gas and electric companies to compete by passing those costs on to ratepayers. Since these companies are still subject to rate base/rate of return regulation in Missouri, it does not make sense to pass these types of expenses through to ratepayers. Shareholders, not ratepayers, must bear the expense of advertisements designed to increase sales of energy resources.

Finally, OPC recommends that the Commission disallow $7,059.53 of charges for Chuck Denton, an advertising consultant who deals with home builders associations, developers, and realtors. OPC maintains that his activities are promotional in nature. OPC points out that in response to a data request, Denton wrote that he was involved in setting up potential ads and material for Lennox Corporation open house and review of possible poster boards or banner for background for MGE floor display in future showcase.

***16** The Commission finds that Denton was primarily engaged in promotional activities and therefore will disallow the expenses associated with his services.

I. Dues and Donations

MGE, Staff and OPC each have different opinions about the appropriate level of dues and donations in this case. OPC argues that the dues and donations made by MGE to various organizations do not provide a direct benefit to rate-payers and should therefore be disallowed. OPC points out that the direct benefit test comes from a previous decision of this Commission. In re Kansas City Power & Light Co., 24 Mo. P.S.C. (N.S.) 386, 400 (1986). In that case, the Commission stated:

> The rule has always been that dues to organizations may be allowed as operating expenses where a direct benefit can be shown to accrue to the ratepayers of the company. Conversely, where that sort of benefit does not appear, disallowance of the dues is required.

After carefully considering the positions of MGE, Staff and OPC, the Commission finds that the Staff's recommendation is the best alternative. Staff proposed the elimination of $53,289 for certain non-American Gas Association (AGA) dues and donations, and an additional adjustment of $53,947 to disallow those portions of AGA dues attributable to lobbying, governmental affairs and marketing. The Staff recommendation includes dues to local chambers of commerce, professional organizations like the American Institute of Certified Public Accountants, and a donation for safety equipment to the Western Missouri Fire Chiefs Association. The evidence shows that the Staff exercised sound judgment concerning the nature of each expenditure. In reviewing AGA dues, the Staff compared the expenditures itemized by the National Association of Regulatory Utility Commissioners (NARUC) audit of the AGA with the standards traditionally used by this Commission to derive a ratio for allowable expense. (Ex. 39HC, pp. 8-9). Overall, Staff's position is the most reasoned, and does not unduly emphasize the quantification of direct benefits, which OPC's analysis does.

J. Community Leadership Department

The issue presented for decision is what portion of the expense booked to MGE's Community Leadership Department should be recovered in rates. MGE believes the entire cost should be allowed in rates. OPC believes that none of the cost should be allowed in rates. Staff recommends that the Commission allow 50 percent of the cost in rates.

Staff's review of the Community Leadership Department records indicate that a substantial portion of the department's functions are not properly chargeable to ratepayers. (Ex. 38HC), pp. 13-17). Some functions which are not properly chargeable to ratepayers include promotion of MGE's corporate image, legislative contacts, civic functions, and charitable activities. On the other hand, Staff identified several functions which are normally chargeable to ratepayers. These above-the-line functions include safety presentations and customer service contacts. Staff maintains that MGE's records were far from comprehensive for purposes of conducting a thorough audit. Balancing the material reviewed by Staff, Staff recommends that the Commission allow 50 percent of the department's test year expense in its revenue requirement. (Ex. 38HC, p. 26).

***17** The Commission finds that 50 percent of the test year expenses of the Community Leadership Department should be allowed in MGE's revenue requirement. A significant part of the functions of the Community Leadership Department relate to promoting the corporate image of MGE or encouraging greater use of natural gas. Therefore, it would be inappropriate to charge ratepayers with 100 percent of the expenses of the Community Leadership Department. At the same time, however, it appears that some of the functions conducted by the department, such as safety training and education, will provide benefits to ratepayers and are properly chargeable to ratepayers.

K. Corporate Costs

1. Executive Salaries

MGE contends that 100 percent of the salaries of George Lindemann, Chief Executive Officer and Chairman of the Board, and Jack Brennan, Assistant Secretary and Vice Chairman of the Board, should be included in the calculation of corporate costs allocated to MGE for ratemaking purposes. MGE witness Janet M. Simpson testified that Lindemann and Brennan are heavily involved in the day-to-day activities of Southern Union Company. According to Simpson, they are in continuous contact with the executive officers of the company in Austin relating to matters of long term and short term strategic planning. Simpson further testified that they are actively involved in establishing and maintaining contacts with bankers, rating agencies and financial analysts. Simpson contends that based on the nature and extent of their involvement, Lindemann and Brennan function as executive officers rather than geographically removed directors.

Staff presents testimony relating to several data requests that it submitted to MGE concerning the time spent by Lindemann and Brennan working as directors or officers of Southern Union Company. Staff testifies that MGE did not provide appointment calendars for 1995 and 1996 but, instead, MGE states 'calendars were not retained' by Lindemann and Brennan. Staff further testifies that in addition to their function as directors/officers of Southern Union, Lindemann and Brennan are officers/directors/employees of Activated Communications, a company controlled by Lindemann that is headquartered in New York City. While at Activated Communications' office in New York City, or while at Lindemann's residence in Florida, these individuals are geographically remote from Southern Union's corporate headquarters in Austin, Texas, and the MGE headquarters in Kansas City, Missouri.

The Commission finds that 50 percent of that portion of the salaries allocated through Southern Union of Lindemann and Brennan should be excluded from MGE's revenue requirement because MGE has not provided sufficient documentation to establish that 100 percent of the activities of Lindemann and Brennan performed for Southern Union provide a benefit to Missouri ratepayers.

The Commission is concerned with the state of the record on this issue. This evidence leaves many unanswered questions regarding the services that Lindemann and Brennan provide to benefit MGE's ratepayers. For instance, how much of their time is spent working for Southern Union? How much is spent working on MGE matters? There appears to be no evidence on jurisdictional allocation between Texas operations and Missouri operations. Does Activated Communications provide services to Southern Union?

***18** Under Section 393.150(2), R.S.Mo. (1994), MGE bears the burden to show that proposed increased rates are just and reasonable. This means that MGE must keep auditable records to show that Lindemann and Brennan provided services to MGE which services benefited Missouri ratepayers. It is not sufficient to request the increase in revenue requirement with no supporting documentation. However, given the supported positions in this record the Commission will rule in favor of Staff's position.

2. Executive Office Lease Expense

MGE contends that the lease costs associated with office space used by George Lindemann and Jack Brennan should be included in the calculation of corporate costs allocated to MGE for ratemaking purposes.

Staff and OPC recommend that the Commission remove the cost of the New York City office space from the corporate costs allocated to MGE because it is an unnecessary, additional expense that MGE would not otherwise incur if its top executive officers, Lindemann and Brennan, maintained an office at the Austin, Texas headquarters of Southern Union.

The Commission finds that MGE failed to prove the necessity of the expense for the New York City office. Thus, the Commission will not allow MGE's revenue requirement to reflect this expense.

3. Incentive Compensation

MGE recommends that the Commission adopt the adjustment proposed by Staff which reflects a four-year average of incentive compensation paid. (Ex. 35, pp. 26-29). OPC believes that the Southern Union incentive compensation plan should be excluded from the cost of service. OPC contends that the incentive compensation plan relates primarily to shareholder-related goals such as increasing profits or net income. (Ex. 42, pp. 25-27; Ex. 43, pp. 13-14).

OPC witness Effron testified at pages 13 and 14 of his rebuttal testimony as follows:

Q. ...To the extent that the incentive compensation program relates to controlling costs, which is arguably a ratepayer oriented goal, should the incentive compensation be included in the cost of service? A. As a general rule, I would agree that if the incentive compensation is related to customer oriented goals, then it should not be excluded from the cost of service. But, and this is a big but, if one of the nominally customer oriented goals of the incentive compensation program is reducing expenses, then that incentive compensation should be included in the cost of service only to the extent that the intended cost containment can be achieved without compromising customer service. If employees are rewarded for reducing costs, without regard to the quality of service, then the employees have an incentive to reduce costs, even if it means compromising the quality of service. Unless the Company can demonstrate that cost reductions pursuant to which incentive compensation has been awarded were achieved while maintaining the quality of service, then the incentive compensation should be excluded from the cost of service. In fact, based on the testimony of OPC witnesses Trippensee and Kind, any cost reductions which the Company has been able to achieve have been realized at the expense of the quality of service. In these circumstances, it would be inappropriate to include any incentive compensation related to expense reductions in the cost of service. [Emphasis added].

***19** The Commission finds that the quality of service is provided by MGE has declined precipitously during the last three years. (Ex. 81, pp. 7-8, Sch. 2).

Nevertheless, MGE is requesting the Commission to have ratepayers pay for an incentive compensation program that ratepayers may have already paid for in terms of a reduction in the quality of service that ratepayers receive.

The Commission finds that the costs of MGE's incentive compensation program should not be included in MGE's revenue requirement because the incentive compensation program is driven at least primarily, if not solely, by the goal of shareholder wealth maximization, and it is not significantly driven by the interests of ratepayers. (Tr. 461-462, 508-512).

4. Stock Option Compensation

MGE granted a limited number of its employees stock options as part of their compensation. Alleging that the cost of these stock options is $431,573, MGE requested that they be included in its cost of service.

The Staff removed this cost on the basis that these are very speculative and not appropriate for ratemaking purposes. In addition, Staff argues that since neither Southern Union nor MGE records an expense on its books associated with the stock options, it is not appropriate to charge MGE ratepayers for the options. (Ex. 59, pp. 17-22).

The effect of granting stock options to employees is to align the interests of shareholders and employees. The interest of shareholders is to maximize shareholder wealth. To maximize shareholder wealth, the firm must maximize revenues and minimize costs.

Minimization of cost while maintaining an appropriate level of quality of service is an appropriate goal. MGE has argued in this proceeding that since it wants to maximize revenue it will maintain service quality at an appropriate level. The Commission does not agree with this argument by MGE because MGE enjoys a monopoly service territory in the State of Missouri. MGE does not have to compete with other suppliers of natural gas to provide service to residential and small business customers. (Tr. 1137-1138). Thus, MGE's argument that its goal of maximizing revenue ensures appropriate quality of service is fallacious. Furthermore, that argument will remain fallacious until the market for natural gas is truly competitive. Having said all that, the Commission finds that the Staff's position on the stock option compensation issue is correct because there is not a sufficient connection between benefits to Missouri ratepayers and benefits to MGE's shareholders to justify the cost of a program that brings the interests of MGE's shareholders and MGE's employees into alignment.

L. Amortization Period for Safety Program Deferrals

MGE's position is that a three-year amortization period is warranted for safety line replacement program costs. MGE contends that a prolonged delay in recovery of these costs denies shareholders a timely cash return of and on their investment. (Ex. 34, p. 15, 11. 3-7). MGE recommends that the Commission increase amortization expense from the Staff's September 13, 1996 accounting run to reflect a three-year amortization period of the Company's deferrals. (Ex. 61, p. 17, 11. 10-13).

***20** Staff and OPC recommend that the safety line replacement program deferrals be amortized over 20 years rather than three years. (Ex. 64, pp. 8- 11; Ex. 66, pp. 11-12; Ex. 42, pp. 27-32).

The Commission finds that a 20-year amortization is appropriate because the line replacements should last at least 20 years. However, the Commission does find that MGE's objection to Staff's argument that MGE is 'trying to change the deal' on this issue as agreed to in the merger case, GM-94-40, is well taken. The rights and obligations from an earlier matter (GR-93-240) which Southern Union agreed to assume in the merger case were subject to a variety of typical settlement agreement conditions, including a proviso that the parties were not 'deemed to have approved or acquiesced in any ratemaking principle or any method of cost determination or cost allocation ....' Therefore, MGE was free to assert that the amortization period for safety program deferral was altered.

The Commission's finding in favor of a 20-year amortization on this issue is not to be construed as an indication that the Commission is not concerned about the safety of gas lines. To the contrary, the Commission takes very seriously its obligation to ensure the safety of gas lines. The Commission had to choose between two extreme positions in this case. It would be helpful to have other proposals in between the extremes presented herein.

M. Depreciation and Amortization Other Than Safety Program

MGE recommends that the Commission authorize the use of a 10 percent depreciation rate with respect to the portion of the costs booked to Account 391 that relates to computer hardware and software. (Ex. 34, p. 14; Ex. 35, pp. 35-38). The Staff maintains that MGE has failed to conduct a thorough depreciation study and that MGE is attempting to improperly select a few assets from a large category of assets for rapid depreciation. The evidence shows that MGE had hired Black & Veatch to conduct a depreciation study of all accounts in 1995. The study specifically indicated that the Account 391 depreciation rates were too low and failed to recognize the actual life of computer equipment. (Ex. 67, p. 12). The study concluded that overall depreciation expense should decrease. However, Staff and MGE agreed that there would be no change in depreciation rates in this rate case. (Ex. 67, p. 12).

The Commission finds MGE's proposal that computer hardware and software be depreciated at a rate of 10 percent per year is appropriate because technology is advancing at such a rapid pace that an owner will frequently find computer hardware and software to be obsolete ten years or less after the date of acquisition.

N. Acquisition Savings

MGE proposes an adjustment that adds expenses to rate base equal to 50 percent of achieved, ongoing savings resulting from Southern Union's acquisition of Missouri properties from Western Resources, Inc. These acquisition savings involve: labor and associated taxes, benefit savings, purchased gas savings, MIS savings, lease cost savings (building and vehicle) and financial savings. (Ex. 34, p. 16). MGE asserts that the basis of the adjustment is the unanimous stipulation and agreement from Case No. GM-94-40. MGE contends that the stipulation and agreement allows MGE to request recovery of the benefits resulting from the acquisition. MGE contends that an equal sharing of these ongoing savings between customers and shareholders is a reasonable ratemaking approach and is consistent with the terms of the stipulation and agreement. (Ex. 34, pp. 16-17).

***21** MGE quantified the purported identifiable annual savings it has already generated at $14,748,912. (Ex. 34, pp. 16-18, and Sch. DND-1-H, p. 5 of 6). MGE states that more than $5,420,000 of these savings has already been realized and flowed through to its ratepayers by the Purchased Gas Adjustment (PGA) Clause. For producing these tangible savings, MGE is requesting that the Commission provide MGE with some tangible recognition. The recognition requested is in the form of adding an amount equal to one-half of these identified, achieved and ongoing savings as an expense for ratemaking purposes. (Ex. 34, p. 16). MGE maintains that Missouri ratepayers have experienced a benefit in terms of decreased natural gas costs. MGE maintains that it has acquired gas supplies at a lower cost than its predecessor (WRI) because MGE tends to bid supply contracts where WRI tended to negotiate its contracts. (Tr. 747-748).

MGE further argues that it has lowered its cost of capital, which is reflected in rates, from what customers would have experienced if WRI had not sold the properties. MGE states that it has achieved this lower cost of capital through refinancing higher cost debt and issuing tax deductible preferred stock. (Ex. 9, p. 18).

Staff's position is that the acquisition savings proposal should not be implemented. Staff argues that the proposal 'imputes' expenses to ratepayers which were not actually incurred by MGE. MGE witness Cummings directly admits in his rebuttal testimony that the 'imputed expenses are not current costs of providing utility service.' (Cummings Rebuttal, Ex. 9, p. 22). MGE's witness Dively testified at the hearing that no part of MGE's acquisition savings adjustment proposal represents actual costs of providing service. (Tr. 670- 671).

Staff points out that the stipulation and agreement from Case No. GM-94-40 merely allows MGE to seek recovery of the benefits from acquisition rather than guaranteeing such recovery.

In sum, the Staff recommends that the Commission reject MGE's proposal because it does not represent appropriate or proper ratemaking policy because the alleged savings are not adequately quantified by MGE; the proposal is not fair and equitable; utilities other than MGE have also downsized without expecting any sharing of related savings; the alleged cost reductions benefited MGE at least up until any rate changes resulting from this proceeding; the proposal represents the equivalent of an incentive plan without any safeguards; the proposal shifts risks of MGE's cutbacks and related cost reductions to its customers; the proposal represents an attempted recovery of the acquisition premium from Case No. GM-94-40; and the proposal would take MGE off of cost of service ratemaking (cost-based rates). (Ex. 72, pp. 4-5). The Staff further argues that adoption of MGE's proposal would reward the Company for providing a lower quality of service while at the same time requesting ratepayers to pay higher than cost-based rates.

***22** The Commission finds that MGE's acquisition savings adjustment should be rejected in total because adoption of this adjustment would be contrary to the provision of natural gas service based on the costs of providing such service and because MGE's experimental gas cost incentive mechanism already rewards MGE's shareholders for making financially sound gas procurement decisions.

O. Street Cut Referendum Fees

The City Council of Kansas City, Missouri, passed an ordinance in April 1996 which, if implemented, would have imposed higher costs on MGE and other utilities which are required to occasionally dig holes (i.e., street cuts) in the city streets. (Ex. 55, p. 30). MGE estimated the increased costs to its customers resulting from the ordinance to be approximately $1,200,000 annually. (Tr. 792-793). In May 1996 MGE started a referendum petition drive to place the ordinance passed by the City Council on the ballot for a public vote. (Ex. 55, p. 30). The petition requested the City Council to either repeal the ordinance or put it on the ballot and let the voters in Kansas City determine whether it should be implemented. (Ex. 88, p. 5; Tr. 790). The City Council rescinded the ordinance. (Tr. 800). MGE requests that the revenue requirement reflect an $18,466 amount which reflects the test period portion of expenses used to help encourage reconsideration of the ordinance. MGE points out that the total expenditure for this effort was approximately $100,000, but only $18,466 fell into the test year period so that is what MGE requests in the revenue requirement.

Staff contends that this would be a nonrecurring expense and not material. OPC contends that this is an inappropriate lobbying expenditure by MGE.

The Commission finds that this type of activity by a natural gas utility has the potential of providing a direct benefit to ratepayers. In this particular case, it appears that MGE's efforts did, in fact, have a substantial direct benefit to ratepayers. The Commission finds that MGE's request that its expenditures during the test year period on the street cut referendum issue be included in its revenue requirement in this rate case is reasonable.

1. Lobbying Expense

OPC proposes an adjustment in the amount of $4,971, which represents an imputed level of lobbying expenses to represent the services MGE provides to a political action committee (PAC). The PAC is known as Missouri Gas Energy Citizens for Responsible Energy. (Ex. 55, p. 47, 11. 10-13). OPC states that MGE incurs direct costs in relation to the PAC.

MGE states that whatever costs it incurs in relation to the PAC are de minimis. (Ex. 53, p. 9, 11. 8-15). The services performed by MGE in relation to the PAC are: (1) withholding employee contributions from payroll checks; and (2) completion of a quarterly report to the State of Missouri.

The Commission finds in favor of MGE on this issue because the proposed adjustment of $4,971 actually equaled the amount of voluntary contributions for the test period made by MGE employees. OPC has not quantified the amount.

P. Weatherization Program and Its Costs

***23** This issue was resolved by the Stipulation And Agreement filed by the parties on October 30, 1996. Please see section I.A. of the Procedural History for the discussion about this Stipulation And Agreement

Q. Property Tax Expense

MGE contends that the most current known and measurable plant balances should be used to calculate an ongoing level of property tax expense. Thus, MGE used May 31, 1996 plant balances in the annualization of property tax expense. (Ex. 53, pp. 4-6).

Staff's position is that the actual property tax assessment date of January 1, 1996 should be used to determine property taxes for revenue requirement purposes. (Ex. 71, pp. 6-8).

The Commission finds Staff witness Featherstone's testimony persuasive where he states:

> MGE will not accrue a property tax expense for any of the plant additions through May 31, 1996 identified in the Rebuttal Testimony of Mr. Kelly until January of 1997. This accrual will only be an estimate for which the Company will not know the actual amount of property tax payments until late in 1997, when the tax bills are distributed by the taxing authorities, usually in November or December of that year.

(Ex. 73, p. 4).

The Commission finds that MGE's proposal would require waiting until the end of 1997 to account for an item of expense for inclusion in this case because this would be a violation of the test year, updated test year or true-up concepts. (Ex. 73, pp.

5-8). Staff's recommendation will be adopted.

R. Uncollectible Expense

The Company accepts Staff's recommended uncollectible expense ratio, but the Company believes that the ratio should be used to compute uncollectible expense relating to revenue from Large Volume Sales and Transportation customers. MGE also believes the ratio should be used to compute uncollectible expense relating to the Company's additional revenues as reflected in the Commission- determined revenue deficiency.

As discussed under issue I.C., Delayed Payment Revenue, the Commission agrees with MGE insofar as the uncollectible expense should be adjusted to reflect additional revenues resulting from the instant rate case. The only remaining issue is whether the uncollectible expense ratio should be applied to Large Volume Sales and Transportation revenue.

Staff maintains that Large Volume Sales and Transportation customers do not normally create bad debt expense. It is reasonable to assume that Large Volume Sales and Transportation customers would not cause the creation of bad debt expense. In order for MGE to prevail, it would have to show that Large Volume Sales and Transportation customers do, in fact, cause the creation of bad debt expense. MGE argues that while it is true that uncollectible accounts are fewer in the Large Volume class, the critical point is that the revenues from Large Volume customers were included in the development of the 1.02 percent uncollectible factor. If revenue from Large Volume customers is excluded from the calculation, the percentage of uncollectible accounts (net chargeoffs) becomes 1.06 percent of revenue from Residential, Small General Service and Large General Service customers. MGE maintains that the 1.02 percentage must be applied to all revenues, including Large Volume Sales, or a mismatch will occur in the calculation of the appropriate amount of uncollectible expense for inclusion in cost of service.

***24** MGE's argument seems persuasive on its face. However, since MGE did not provide any evidence showing the calculation of 1.02 percent or 1.06 percent to be the appropriate level of the bad debt expense, the argument fails. In fact, MGE relies, again, on the Staff's calculation of the bad debt expense factor to be 1.02 percent. Staff witness Larry Cox stated that MGE's records and production of information was so deficient that he was not able to do a thorough examination to calculate the uncollectible expense factor. Thus, MGE's position that Large Volume Sales customers' and Transportation customers' revenue should be included with regard to the uncollectible expense factor is completely without merit. The Commission finds that the Staff's approach is the more reasonable approach on this issue.

S. Income Tax

1. Adjustment to Tax Calculation for Equity Portion of SLRP Carrying Cost Deferrals

MGE's position is based on an accounting authority order issued by the Commission in Case No. GO-94-234. In that order the Commission authorized MGE to defer and book to Account No. 182.3 depreciation expense, property taxes and carrying costs at 10.54 percent for certain costs. However, Ordered Paragraph 3 of that same order was quite clear that nothing in the order was to be considered a finding of the Commission in relation to ratemaking treatment. (Commission Order, Case No. GO-94-234, p. 4).

Staff asserts that the actual carrying costs incurred by MGE are reflected by applying the allowance for funds used during construction (AFUDC) rate. (Exhibit 67,

p. 9).

The Commission finds that Staff's position is more reasonable on this issue because the order upon which MGE's position is based specifically provides that ratemaking treatment to be afforded the deferred amounts is reserved. Furthermore, MGE makes no claim that 10.54 percent is an accurate reflection of its actual financing costs during the deferral period. (Tr. 916). The Commission is of the opinion that MGE's revenue requirement in this rate proceeding should reflect actual carrying costs and that the AFUDC rate proposed by the Staff is reflective of actual carrying costs.

2. Adjustment to Tax Calculation for Fifty Percent of Acquisition Savings

As discussed in issue II.N., Acquisition Savings, the Commission rejects MGE's proposal to recognize acquisition savings in rate base. Therefore, there are no income tax consequences associated with the alleged cost reductions resulting from Southern Union's acquisition. (Ex. 64, p. 13). Thus, this issue has become moot.

T. Other Polsinelli, White Charges

This is an issue between MGE and OPC. OPC maintains that MGE's revenue requirement should reflect the elimination of $22,056 in legal fees incurred by MGE in a Kansas Pipeline Partnership (KPP) rate case before the Kansas Corporation Commission. OPC maintains that MGE has failed to show a connection between the KPP rate case and the provision of utility services to MGE's Missouri rate-payers.

***25** MGE's witness Kevin J. Kelly has testified that MGE and KPP have negotiated a contract under which MGE purchases gas, the cost of which is passed directly on to MGE ratepayers. This evidence by MGE appears to be uncontroverted. Therefore, the Commission finds that MGE has demonstrated a strong connection between the KPP rate case before the Kansas Corporation Commission and MGE's rates applicable to Missouri ratepayers. Thus, the Commission finds that the $22,056 of legal fees incurred by MGE for this Kansas rate case should be included in the revenue requirement of MGE.

U. Loaned Executive

This issue was settled between MGE and OPC prior to conclusion of the evidentiary hearing.

III. Rate Base

A. Safety Program Deferrals

1. Carrying Cost Rate

MGE's position is that the Commission should apply a carrying cost rate of 10.54 percent because the Commission issued an accounting authority order on September 28, 1994, in Case No. GO-94-234 which mentioned carrying costs at 10.54 percent. That order provides that 'MGE is authorized to defer and book to Account No. 182.3, beginning February 1, 1994 and continuing through January 31, 1997, depreciation expense, property taxes, and carrying costs at 10.54 percent, on the costs incurred to repair or replace facilities located in mobile home parks, replace MGE-owned and customer-owned service and yard lines ....' That order also provides that nothing in the order 'is to be considered a finding of the Commission of the reasonableness of the expenditures involved herein, or of the value for ratemaking purposes of the expenditures and property herein involved, ...and the Commission reserves the right to consider the ratemaking treatment to be afforded these expenditures in any later proceeding.' [Emphasis added]. MGE argues that not only did the Company rely on this accounting authority order for preapproval of the 10.54 percent carrying cost rate, but that, implicitly, the financial community at large must be able to rely upon accounting authority orders. (Ex. 61, p. 7).

The Commission finds that MGE has taken the application of accounting authority orders well beyond their intended purpose. Accounting authority orders allow utilities to book certain expenses in certain ways. However, accounting authority orders have no direct ratemaking impact. It seems redundant for the Commission to elaborate on this point since the accounting authority order itself from Case No. GO-94-234 states that the order is not to be considered a finding of the Commission regarding values for ratemaking purposes. Since MGE has based its position on the Commission's order from GO- 94-234, which by its very terms does not have a ratemaking impact, MGE's position on this issue is not persuasive. The Commission finds in favor of the Staff on this issue because the Staff's proposal shows a carrying cost which is more reflective of the actual carrying cost associated with the gas safety line replacements. (Ex. 65).

***26** 2. Period Through Which Deferrals Are Computed

MGE contends that the Commission's order in Case No. GO-94-234 requires it to compute deferrals through January 31, 1997 on safety-related plant for ratemaking purposes. (Ex. 34, pp. 14-15; Ex. 61, pp. 10-13).

Staff's position is that safety program deferrals should be cut off at May 31, 1996, the end of the updated test year in this case. Staff states that it has updated these deferrals through October 31, 1996 under the Commission's true-up order. (Ex. 175, p. 2). OPC contends that deferrals of safety line replacement plant included in rate base should be computed at the same date used for other plant-related components of rate base. (Ex. 42, pp. 5-8). In essence, the Commission has already decided this issue in two respects. First, the true-up order issued in this case is quite clear insofar as safety-related plant in service is to be trued-up through October 31, 1996. Second, the Commission's order in GO-94-234, upon which MGE places so much reliance, states very clearly that the accounting authority order does not have any effect upon ratemaking issues. Thus, the Commission finds that the Staff's position is correct.

3. Dismantling Costs, and 4. Unamortized Balance of Deferrals from Case No. GO-94-234

At a conceptual level, these issues are identical to issue III.A.2. MGE places undue reliance on Case No. GO-94-234 in that the order in GO-94-234 is an accounting authority order which specifically reserved ratemaking treatment.

The Commission in its true-up order in this case specified true-up through October 31, 1996. The Staff has correctly trued-up these balances through October 31, 1996. Staff's approach is consistent with cost of service/historical test year ratemaking principles, and the Commission finds that the Staff's approach is correct. (Ex. 65).

B. Offset for Rate Base Reductions Eliminated by Purchase

The unanimous stipulation and agreement in the acquisition case, Case No. GM-94-40, in which Missouri Gas Energy acquired the Missouri gas properties of WRI, contains the following language:

> Southern Union [i.e., MGE] agrees to use an additional offset to rate base in any Southern Union filing for a general increase in non-gas rates in Missouri completed

in the next ten years to compensate for rate base deductions that have been eliminated by this transaction. The amount of the offset for the first year shall be $30.0 million. The amount shall reduce by $3.0 million per year on each anniversary date of the closing of the subject transaction.

(Ex. 71, p. 4; see also p. 6, para. 8, Unanimous Stipulation And Agreement in Case No. GM-94-40).

MGE argues that the stipulation and agreement is silent as to the precise nature of the rate base reduction eliminated by the transaction. MGE argues that instead of the two-year amortization proposed by the Staff and OPC, which would reduce rate base by $24 million, the appropriate amortization period for purposes of this case is two years and four months, which would reduce rate base by $23 million.

***27** The Commission finds that Staff and OPC correctly interpreted and applied the stipulation and agreement from GM-94-40 wherein it states: 'The amount shall reduce by $3.0 million per year on each anniversary date of the closing of the subject transaction.' (Ex. 71, pp. 5-6).

IV. Capital Structure and Rate of Return

A. Required Capital Structure to Implement Rates

Please see the Commission's discussion of this issue at pages 12 through 14 (Motion to Dismiss on Basis that MGE Failed to Comply With Capital Structure Condition in Case No. GM-94-40).

B. Capital Structure

MGE, OPC and the Staff agree that MGE's capital structure is as follows: common equity -- 33.13 percent; long term debt -- 54.12 percent; preferred stock -- 12.75 percent. OPC's agreement to this capital structure is conditioned on the assumption that the Commission will determine that the preferred stock should be treated as equity, which, of course, is the subject of OPC's motion to dismiss the case as well as issue IV.A.

C. Cost of Debt

MGE, Staff and OPC agree that the cost of long term debt for purposes of this case is 8.21 percent. (Ex. 90, pp. 26-28; Ex. 91, p. 2; Ex. 78, Sch. 2; Ex. 99). Riverside/Mid-Kansas claim that the cost of debt is 7.739 percent. The difference between the two proposals stems from the fact that MGE's proposed cost of debt includes losses on reacquired debt recorded in Account No. 189. These reacquired debt costs are associated with high cost debt that was outstanding prior to the acquisition of Missouri properties. Since these costs were not incurred in financing the acquisition of the Missouri properties, these costs should not be considered in determining the cost of debt for MGE's Missouri operations. (Ex. 105, p. 12).

The Commission finds that Southern Union incurred the reacquisition debt costs recorded in Account No. 189 in an effort to lower its overall cost of capital. This cost may legitimately be passed through to ratepayers. (Ex. 91, p. 18).

D. Cost of Preferred Stock

MGE, Staff and OPC agree that the appropriate cost of preferred stock for purposes of this rate case is 10 percent. (Ex. 90, pp. 28-29; Ex. 91; Ex. 76, Sch. 13; Ex. 99).

E. Rate of Return on Common Equity

MGE's position is that it should be authorized to earn a rate of return on common equity of 12.25 percent. (Ex. 90, pp. 30-71, 75-76). MGE witness Fairchild's recommendation is based on the results of two analyses. First, the constant growth discounted cash flow model was applied to a group of 19 other gas local distribution companies (LDCs). Second, risk premium methods based on leading studies for utilities in the academic and trade literature were also applied. Dr. Fairchild testifies that, taken together, these analyses implied that the cost of equity for MGE is in the range of 11.5 to 12.5 percent. Dr. Fairchild testifies that he selected a rate of return on common equity for MGE above the midpoint of 11.5 to 12.5 percent (he selected 12.25 percent) based on two considerations. First, the range gives approximately equal weight to the discounted cash flow analysis, which tends to be biased downward because investors expect near-term growth rates to be lower than longer-term growth as LDCs prepare for a more competitive industry. Second, Dr. Fairchild testifies that this cost of equity range does not recognize flotation costs incurred in connection with sales of common stock. (Ex. 90, pp. 6-7).

***28** OPC recommends that Southern Union be authorized a 10.75 percent return on equity. (Ex. 99, pp. 14-33). OPC witness Burdette testifies that MGE should be allowed a return on common equity of 10.75 percent. This return on equity was determined using the discounted cash flow method applied to a group of nine comparable companies and supported by a capital asset pricing model analysis and a market-to-book ratio analysis. (Ex. 99, p. 14).

Staff recommends a return on equity range of 11.30 to 12.35 percent from a financial analysis viewpoint. However, Staff believes that the Commission has the power to consider poor customer service when determining a reasonable return on equity. (Ex. 76, pp. 32-49; Ex. 78, pp. 4-10; Ex. 81, all).

The Commission takes very seriously its obligation to ensure that MGE provides safe and adequate service under reasonable terms and conditions. After hearing the many serious customer complaints at local public hearings in St. Joseph, Kansas City and Joplin, Missouri, and after reviewing the testimony provided by the Office of the Public Counsel and the Commission's Consumer Services Department, the Commission has grave reservations about whether MGE is providing an adequate level of service quality to Missouri customers.

The number of customer complaints has increased substantially since Southern Union acquired the Missouri properties from WRI in February of 1994. For the fiscal year ending June 30, 1996, the Commission's Consumer Services Department received 941 complaints relating to MGE operations. In contrast to that number, during fiscal year 1993 (the last full fiscal year that WRI operated the territory) there were 540 customer complaints. This represents an increase in the number of customer complaints received by the Commission's Consumer Services Department of 74 percent. (Ex. 81, pp. 7-8).

The Commission finds that the appropriate return on equity for purposes of establishing MGE's revenue requirement in this case is 11.30 percent. This is the low end of the range of acceptable return on equity figures provided by the Staff. (Ex. 76, pp. 32-49; Ex. 79, pp. 4-10).

1. Increased Residential Customer Charge

OPC contends that Southern Union's return on equity should be adjusted downward by 25 basis points because the customer charge is being increased from $9.05 to $15.00 in this case. OPC witness Burdette testifies that with the proposed increased customer charge, 69.74 percent of MGE's nongas residential revenues would not vary with gas usage, leaving only 30.26 percent variable with gas usage. (Ex. 100, pp. 25-26, Sch. MB-1-R). With the current $9.05 customer charge, Burdette concludes that since MGE's revenues will be less variable as a result of the increased customer charge, the reduced risk should be reflected in a lower authorized return on equity. In making this analysis, Burdette assumes a $9.05 customer charge, the margin residential revenue requirement, billing determinants, and rates from MGE witness Dittemore's direct testimony. MGE's position is that the adjustment proposed by OPC is not based on competent and substantial evidence in that the theory is based on an assumption that MGE's current customer charge produces a percent of nongas revenues comparable to OPC's group of 'comparable' LDCs. MGE states that the recommendation is based on a conclusory allegation that a reduction in the variability of MGE's earnings through a higher customer charge would make those earnings less risky, which, in turn, justifies a reduction in the authorized return on equity.

***29** The Commission finds that OPC has failed to carry its burden of proof on this issue. At page 25, lines 23 through 22, Burdette admits that in calculating the portion of MGE's revenues that do not vary with gas usage, it was assumed, along with the $9.05 customer charge, that the marginal residential revenue requirement, billing determinants and rates from Dittemore's direct testimony would be used. The revenue requirement resulting from this order is significantly less than that which MGE proposed in its testimony. Therefore, an analysis which assumes the revenue requirement used by MGE fails. Thus, the Commission declines to adopt the 25 basis point downward adjustment proposed by OPC because of the increased customer charge.

F. Adjustment for Weather Normalization Clause

This adjustment is premised on the assumption that the Commission will adopt MGE's proposed weather normalization clause. As discussed in that section of this Report And Order, MGE has not convinced the Commission that the adoption of a weather normalization clause is in the interests of ratepayers. Since the weather normalization clause is rejected by this Report And Order, this particular issue which is premised on the adoption of the weather normalization clause thereby becomes moot.

V. Customer Service Issues

As stated previously, the Commission has serious concerns as to whether MGE is providing an adequate level of service. This matter has been addressed in other sections of this Report And Order where appropriate.

VI. Class Cost of Service and Rate Design

A. Class Cost of Service Study

1. Allocation of Costs for Services, Meters and Regulators, 2. Allocation of Costs for Mains, 3. Class Cost of Service Results, and 4. Class Rate Increases

These four issues were addressed in Section I.B., infra.

B. Rate Design

1. Miscellaneous Service Charges

MGE proposes that miscellaneous service charges be more closely aligned with the costs of providing these services. (Ex. 30, pp. 4-5; Ex. 31, pp. 2-3).

OPC recommends that the charges currently reflected on MGE's tariff be maintained and MGE's request to change these tariffed rates be denied because MGE has failed to provide a complete set of work papers to support the proposed changes. (Ex. 19, pp. 11-12).

The Staff contends that MGE's collection, disconnect, reconnect and request for meter reading charges should be maintained at the current tariffed rate because the Company could not provide Staff with documentation to quantify or substantiate the proposed charges. (Ex. 23, pp. 3-4).

The Commission will deny MGE's proposal to modify miscellaneous service charges because MGE has failed to adequately substantiate the proposed changes.

2. Customer Charges

The issue is what the Commission should set as the monthly customer charge for MGE's customers. The current charge is $9.05 per month which was approved by the Commission in 1993. MGE's cost study filed with its direct testimony identified a monthly customer cost of $18.21. (Tr. 1826). Although MGE identified costs at that level, MGE witness Gillmore testified that he used his judgment to recommend an increase in the monthly charge to $15.00 rather than $18.21 given the magnitude of an increase from $9.05 up to $18.21. (Tr. 1901).

***30** OPC recommended a monthly residential customer charge of $9.75. (Tr. 1911-1915). The Staff recommends that the monthly residential customer charge be set at $9.81. Staff has developed its customer charges based on direct costs for the provision of a meter, regulators, service line, meter reading and billing that are traditionally collected through the customer charge, and believes that the Commission should follow that approach in this case and order the residential customer charge at $9.81 per month.

The Commission finds that the residential customer charge should remain at $9.05 per month. The customer charge for Small General Service customers should be increased from $9.05 to $11.05 per month. This result brings MGE closer to the practice of other Missouri gas companies. (Ex. 171). The customer charge for Large General Service should remain at $65.80 per month. The customer charge for Large Volume Service should remain at $409.30 per month. The Commission finds that the resulting percentage contribution to revenue requirement should remain at 68.22 percent from Residential Service, 0.01 percent from Unmetered Gas Lights, 21.22 percent from Small General Service, 2.65 percent from Large General Service, and 7.9 percent from Large Volume Service, as reflected in Staff's filing on January 17, 1997.

The increased revenue requirement for Residential, Large General Service and Large Volume Service will be recovered through variable use charges (i.e., commodity charge for Residential and Large General Service customers, sales charge for Large Volume Service taking sales gas, and contract demand charge for Large Volume Service customers who are transporting gas). The commodity charge is referred to as the 'energy charge' on the residential bills, and is not to be confused with the wholesale cost of the natural gas commodity. These charges are shown at pages 25, 28, 31, 42 and 44 of MGE's tariff. The increased revenue requirement for Small General Service will be recovered primarily from the increased monthly customer charge and the remainder of its revenue requirement increase will be from the commodity charge.

3. Overrun Penalties

See issues VII.K. and VII.L.

4. Class Rate Increases

See issues VI.B.2., infra.

VII. Tariff Issues

A. Weather Normalization Clause

MGE proposes a weather normalization clause (WNC) which would reduce the impact of temperature variations on its revenue stream. Through the WNC the volumes of gas for which customers are charged are adjusted to reflect 'normal' weather, as defined in this case. During a month that is colder than normal, the volumes of gas would be reduced to a normalized level. On the other hand, during a month that is warmer than normal, the volumes charged would be increased.

Staff and OPC are against approval of the WNC because it has the effect of changing the per-unit rate a customer pays for actual usage. (Ex. 28, pp. 4-5). Staff witness Hubbs quotes from a previous Commission decision regarding a similar proposal by MGE (Case No. GT-95-429). The Report And Order in that case stated:

***31** Approval of the WNC tariff would result in a de facto change in MGE's rates. Under the weather normalization clause a customer would pay for more gas than he actually used in an unusually warm month. In that month, the customer would have paid an effective per-unit rate for his actual usage greater than MGE's current tariffed rate. In an unusually cold month the customer would pay for less gas than he actually used. In that month, the customer would have paid a lower per-unit rate for his actual usage than MGE's current tariffed rate.

(Ex. 28, p. 4).

Staff also maintains that approval of the WNC would constitute single-issue ratemaking. Hubbs testified that approval of the WNC would allow MGE to change, in an uncertain amount, the maximum rate approved for MGE's services, and that allowing MGE to modify actual usage would change the effective maximum rate the Commission sets for MGE in this proceeding. (Ex. 28, pp. 5-6). These changes would occur outside the context of a rate case. Thus, the Commission's concerns expressed in Case No. GT-95-429 about single-issue ratemaking are still valid, according to Hubbs.

Staff goes on to state that if the Commission were to allow MGE to have the weather normalization clause, it should not be mandatory but should be allowed at the customer's option and should be further conditioned as set forth in Dr. Proctor's rebuttal testimony.

It is clear to the Commission that approval of the WNC proposed by MGE would benefit MGE insofar as the variability of its revenues resulting from weather changes would be reduced, thus reducing MGE's business risk. The WNC would shift virtually all weather-related risk onto ratepayers. In the event that the Commission would authorize a WNC similar to the one proposed herein, the Commission would seriously consider a downward adjustment to return on equity as proposed by OPC. Also, there may be other conditions that would have to be implemented along with the WNC. The Commission notes that ratepayers already bear a substantial amount of risk associated with wholesale gas price changes under MGE's Experimental Gas Cost Incentive Mechanism. On balance, the Commission finds that the WNC would be a detriment to ratepayers because weather-related risks would be assumed by ratepayers, and ratepayers are already able to levelize their payments by entering into a levelized payment plan. The Commission finds that approval of the WNC would be a de facto abdication of the Commission's responsibility to set rates. The fact that the WNC technically adjusts volumes rather than rates does not cure this fundamental problem. Thus, the Commission will not approve the WNC.

B. Gas Safety Project Rider

MGE proposes a gas safety project rider (GSPR) to recognize gas safety program expenditures in the cost of service on a more expedited basis than through a traditional rate case mechanism. MGE maintains that this benefits customers through smaller and less sharp rate changes, and benefits shareholders through a more timely recognition of these expenditures in cash earnings. MGE also proposes an incentive regulation rider (IRR) to replace, on an experimental basis, traditional rate cases. The two riders are a package. The IRR issue is listed as issue VII.C. in this Report And Order.

***32** MGE proposes a GSPR which would cause rates to be adjusted annually to reflect depreciation, property taxes, and return on the safety plant additions. The GSPR is prompted by the Commission's enactment of extensive changes to its gas safety rules in 1989, five years before Southern Union acquired its Missouri gas properties from WRI. MGE currently spends more than $20 million per year on safety line replacements. Due to the magnitude of these costs and the fact that they reflect replacement of existing pipes and not addition of new customers, timely rate recognition is essential to the financial well-being of MGE.

The Staff points out that the Commission has approved accounting authority orders for MGE's as well as WRI's safety plant additions. MGE is seeking rate recovery of those amounts in this proceeding. In addition, MGE wants to replace the accounting authority order process with the GSPR. Under the GSPR proposal, rates will automatically increase annually following a 45-day Staff review period, to reflect the revenue requirement impact of safety plant additions completed by March 31 of each year. (Ex. 80, pp. 5-6). The GSPR annual rate change would reflect only the revenue requirement impact of the gas safety program and would not reflect the impact of any revenue requirement changes related to other facets of MGE's operations. (Ex. 80, p. 6). Under the proposal, the Staff would look only at the prudence of the gas safety plant expenditures and the accuracy of MGE's calculations in deriving the proposed GSPR rate increase amount during the 45-day review period. (Tr. 1401-1402). If the expenditures were found to be prudently incurred and MGE's calculations found to be correct, rates would be automatically increased.

Staff, as well as OPC, argue that this would be unlawful single-issue ratemaking insofar as it would be the isolated examination of the prudence of the gas safety expenditures. They maintain that the GSPR ignores revenue requirement changes in other rate base items, including nonsafety plant additions, depreciation accruals, deferred income taxes, contributed plant, cash working capital, as well as changes in the levels of revenues and nonsafety expenses incurred by the Company. (Ex. 80, p. 7). Staff maintains that all of these events or transactions with potential revenue requirement impact must be examined when considering a rate change based on safety expenditures to determine if the actual revenue requirement of MGE has changed since the last time rates were set for the Company. According to Staff, 45 days to examine the rate impact is not sufficient for a reasonably comprehensive review of all the relevant ratemaking factors. (Ex. 80, p. 7).

The Commission will reject the GSPR because it would constitute unlawful single-issue ratemaking. State ex rel. Utility Consumers Council v. Public Serv. Comm'n, 585 S.W.2d 41, 49 (Mo. en banc 1979). In addition, the Commission will reject the GSPR because 45 days is not sufficient time for the Staff and Commission to conduct a thorough review of all relevant factors relating to gas safety investments by the Company, and the Commission foresees the need for suspensions of GSPR adjustments with drawn-out, fully litigated cases similar to the current ACA process. For all of the above reasons, the Commission will reject MGE's proposal for a gas safety project rider.

C. Incentive Regulation Rider

***33** MGE proposes an incentive regulation rider (IRR) which would replace the traditional ratemaking process used by the Commission for gas corporations. Under the IRR, MGE would share earnings with customers on a 50/50 basis where MGE's return on equity is between 12.80 percent and 14.80 percent. MGE would share earnings with customers on a 75-percent-to-customers-and-25-percent- retained-by-Company basis where MGE was achieving a return on equity in excess of 14.80 percent.

Staff recommends that the Commission reject MGE's IRR proposal for numerous reasons. Staff points out that incentive regulation has been approved by the Commission for Southwestern Bell Telephone Company and Union Electric Company. However, at the time of approval of incentive regulation for those companies, each company had been achieving an adequate level of earnings to support their operations for some time prior to implementation of incentive regulation. Obviously, as shown in this case, MGE does not believe that its earnings are adequate. Staff witness Oligschlaeger testified that:

[T]he root problem with MGE's incentive regulation proposal is that MGE is trying to reconcile its desire for incentive regulation with the fact that it is an increasing cost utility that will require periodic rate increases on account of its gas safety program, among other things. The need for frequent rate increase intuitively does not tie into the normal conception of incentive ratemaking, wherein a utility's ability to increase rates is generally restricted as part of the incentive 'bargain'. MGE has tried to make the pieces fit together by proposing to enhance its abilities to raise rates on an annual basis to cover increasing costs through the GSR while availing itself of the opportunity to gain the benefits of incentive regulation through the IRR. The difficulty is that making incentive regulation 'workable' for an increasing cost company in essence means skewing incentive regulation against the interests of its customers, as MGE's proposals in this proceeding show.

(Ex. 80, p. 18).

Another concern expressed by Staff concerns the auditability of MGE's operations under the IRR. (Ex. 50, p. 11). Under the IRR, reports would need to be filed on a timely basis, meetings with Company personnel would need to be conducted in a timely fashion, and MGE's books and records would need to be completed accurately and on time; based on the difficulty Staff experienced during the audit for this case, these matters pose a significant concern. (Ex. 50, p. 11). Staff is also concerned about Commission approval of an incentive regulation plan for a company which has a poor customer service record, as shown in this case, and believes that these problems need to be corrected before the Commission considers giving the Company the ability to retain excess profits as an incentive to perform better. (Ex. 50, pp. 11-12).

As stated before, the Commission has serious concerns about the adequacy of the service provided by MGE to ratepayers. As pointed out by Staff witness Proctor, the danger with allowing a local distribution company to recover margin costs through an incentive mechanism is that the quality of service to customers could be substantially decreased as the local distribution company cuts its costs in an effort to make additional profits. (Ex. 107, p. 3). The Commission will not approve this type of incentive regulation for nongas costs for MGE, which could exacerbate the customer service problems of MGE.

D. Economic Development Rider

***34** This issue concerns the 'prospective tariff language' aspect of the economic development rider (EDR). The issue is whether there should be changes made to the existing tariff language. MGE filed a proposed tariff seeking to reduce the percentage amount of the existing discounts. The changes would be as follows: In the first year, from 50 percent to 30 percent; in the second year, from 40 percent to 25 percent; in the third year, from 30 percent to 20 percent; and in the fourth year, from 20 percent to 15 percent. The 10 percent amount in the fifth year would remain unchanged. There have been no new customers added to the EDR since December 1994. (Ex. 23, p. 6; Tr. 1609). Gillmore of MGE testified that recent changes in the gas industry, in his opinion, have made EDRs serve very little, if any, purpose. (Ex. 31, p. 3). Gillmore commented that it was MGE's original intention to eliminate the EDR entirely, but he agreed to keep it in place as a result of requests from local governments who view it as important to their efforts to attract new industry. (Tr. 1602). MGE states that since its shareholders are financing 75 percent of the discounts (if Staff and MGE's position on issue I.B. prevails), then MGE believes that those shareholders should have a very significant voice in being able to set the level of discounts that they are funding. (Ex. 9, p. 6).

The Commission finds that MGE's position on this issue is reasonable. Therefore, the Commission will approve tariffs reflecting the changes proposed by MGE.

E. Curtailment Plan

See issues VII.K. and VII.L.

F. Facilities Extensions

This issue involves how much developers will be required to pay for main extensions to new developments. There is no revenue requirement impact associated with the issue in this case. However, it presents a question as to what type of tariff language will be approved for future situations. The resolution of this issue will have an impact on future rates. MGE's proposal contemplates a case-by-case analysis to be done in older to calculate the cost to be charged to developers for facilities extensions.

The Developers want MGE to have an extension rule with specific dollar amounts per foot of pipe so it is easy for the Developers to calculate how much they have to pay, and how much they may get back as a refund when customers move into the new homes. (Ex. 123, p. 6; Ex. 125, p. 11). The Developers' position is apparently quite similar to the current procedure, which resulted from a recent settlement in a complaint case (GC-96-287).

MGE maintains that the current policy causes customers who are currently on the system to cross-subsidize residential customers in new subdivisions.

MGE has not provided evidence to substantiate its claim that the current procedure implemented pursuant to the settlement of GC-96-287 causes cross- subsidization to the benefit of new residential subdivisions. The Commission finds that MGE's proposal to determine the investment by real estate developers and main extensions by an 'analysis' under Section 9.03 would grant too much discretion in MGE in calculating investments to be made by real estate developers. Since MGE has not provided sufficient evidence to justify modification of the facilities extension tariffs from the status quo, the Commission will not approve the facilities extension tariffs. The Commission would reconsider whether to approve a facilities extension tariff that modifies the per-foot charges for extensions if the proposal is supported by competent and substantial evidence as to the per-foot charges.

***35** With respect to the revisions and clarifications suggested by Staff, the Commission suggests that MGE and Staff carefully discuss the terms of a proposed facilities extension tariff prior to the filing thereof.

G. Large General Service (LGS)

The issue identified as '1)' at page 56 of the Hearing Memorandum has been resolved. MGE acknowledged that the applicable section should continue to allow for monthly usage up to 3,000 mcf on this rate. (Ex. 32, p. 22).

The remaining issues relating to LGS appear below.

1. Whether to Offer Transportation Service to LGS Customers Without Electronic Gas Metering (EGM)

Transportation customers take on the responsibility of acquiring their own gas supplies and having them transported over one or more interstate pipelines to the MGE distribution system. Sales customers, on the other hand, do not have that responsibility because the local distribution company ensures that supplies are available for such customers. MGE proposes that LGS customers moving to transportation would not have to install electronic gas measurement (EGM) devices. Electronic gas meters allow usage measurement to be done remotely at practically any time and for the data to be available on a computer bulletin board for MGE and the customer to access. This is in contrast to a gas meter without an EGM attachment where a human being must be dispatched to read and report back what is observed on the dials. The current tariffed rate for EGM installation is approximately $5,000. MGE has stated that it believes that a requirement for EGM for LGS customers would likely make transportation service uneconomical for them. (Ex. 32, p. 23).

Staff is opposed to MGE offering transportation without requiring EGM. (Ex. 20, pp. 11-16). MGE continues to support the Commission's decision to require EGM for Large Volume Service (LVS) customers. MGE contends that the use of EGM is not necessary for LGS customers because LVS customers make up approximately 30 percent of the throughput on the MGE system, while the LGS class represents less than 5 percent of MGE's purchases for resale. (Ex. 70, p. 7). Langston testified that the LGS class is a 'very small class of customers that has very little impact on MGE's overall operations and represents an ideal test category for MGE to utilize in developing alternatives for further unbundling activities. At this time, we do not think that the lack of EGM will present a problem, but we won't know unless we try it, at least on an experimental basis. ' (Ex. 70, p. 8).

MGE did not propose making transportation services available to LGS customers as a test or experiment. However, MGE witness Langston said that MGE is not opposed to the Commission treating this as an experiment for a three-year period. (Tr. 1578-1579).

Staff opposes the proposal without the requirement of EGM because of the detrimental impacts which will accrue to MGE's sales customers by the elimination of accountability and protections afforded by EGM. Staff witness Hubbs testified that without EGM for the LGS class, MGE will not have the ability to assign and bill upstream costs to the transportation customers who are responsible for causing MGE to incur interstate pipeline costs and penalties, and that without EGM equipment, MGE will have no effective method to assign such costs and penalties to the appropriate customers. (Ex. 28, p. 12).

***36** The Commission will not approve transportation for LGS customers without EGM at this time as a result of the risk of unfair allocation of upstream costs and penalties to other transportation customers.

2. Whether to Require a Warning to Transportation Customers

Staff witness Hubbs has recommended that a warning be required in every transportation contract. Hubbs is concerned primarily with smaller and less knowledgeable potential customers in the LGS class. (Ex. 28, p. 17).

The Commission will not require this warning because the Commission will not approve LGS customers' use of transportation service at this time.

3. Standby Sales Service

This item has become moot because the Commission is not authorizing MGE's proposal to provide transportation services to the LGS class.

4. Whether to Incorporate LVS Transportation Tariff Provisions into LGS Tariff Sheets

This item, shown at page 162 of the Staff's initial brief, has become moot because the Commission is not authorizing MGE's proposal to provide transportation services to the LGS class.

5. Whether to Implement Balancing Provisions for LGS Transportation Customers

This item has become moot because the Commission is not authorizing MGE's proposal to provide transportation services to the LGS class.

H. Large Volume Service (LVS)

1. Imputation of Revenues for Customer Charges Relating to LVS Meters

MGE is not collecting customer charges on 70 meters of Large Volume customers in cases where those meters were installed for the convenience of the Company.

This practice, begun by WRI, is based on an interpretation of the following tariff provision:

> When more than one meter or metering facility is set at a single address or location for customer's convenience, a separate customer charge will be applicable

for each meter or metering facility.

(Ex. 33, p. 3). MGE maintains that where the meter is set for MGE's convenience rather than the customer's convenience, it is not appropriate that MGE charge for those meters.

The Staff would have the Commission impute revenues on these 70 meters even though MGE is not collecting that money.

The Commission finds that MGE's interpretation of the tariff is reasonable and will rule in favor of MGE on this issue.

2. Costs of LVS Customer Switching Between Transportation and Sales Service

Staff is opposed to the elimination of the currently tariffed provision that prohibits an LVS customer from switching from transportation to sales service without payment of certain costs. Staff recommends that this provision as quoted on page 21 of Hubbs's rebuttal testimony be maintained, and MGE concurs in its reply brief.

The Commission finds that the provision as quoted on page 21 of Hubbs's rebuttal testimony should be maintained to ensure that customers switching from transportation to sales service pay appropriate costs.

3. Reduction of Commodity Portion of 'Minimum Transportation Charge' from $0.075 per mcf to $0.005 per mcf

***37** MGE's witness Dennis Gillmore conducted a study through which he determined that MGE should be allowed to reduce the commodity portion of the minimum transportation charge as low as $0.005 per mcf.

Staff witness Hubbs testified that the current commodity flex rate is approximately one-fourth of the commodity rate the Commission has previously determined is needed to recover the cost of service for this class, and that the Company's proposal of $0.005 per mcf is less than 2 percent of the currently effective, Commission-approved commodity rate and that, in his opinion, the Company's proposal would be the same as giving the service away. (Ex. 28, pp. 24-25).

The Commission finds that MGE has made a showing that its tariff should be amended to allow it to reduce the commodity portion of the 'Minimum Transportation Charge' to $0.005 per mcf and the Staff did not convincingly rebut MGE's position. The Commission recognized the regulatory problem inherent with flexdown provisions in its decision in Case No. GR-95-160. (See Section I.D., Flex Revenue, of this Report And Order).

The Commission will apply the standard established in GR-95-160 to MGE in future rate cases. The Commission will clarify, however, that the avoidance of 'imminent by-pass' includes the loss of a customer because of a competitive alternative.

In MGE's next rate case, MGE should provide a current analysis of the necessity to flex down to retain the customers. Staff should review that analysis and make its own determination of whether the flex down was necessary to retain the customers. Staff is also expected to verify that the flex down arrangement recovers the variable costs associated with serving the customers along with a reasonable contribution to fixed costs.

As part of its compliance filing, MGE's tariffs shall reflect the three- pronged standard adopted by the Commission in Case No. GR-95-160 and reiterated here. The tariff shall reflect that any **special contract** arrangements: (1) were necessary to avoid imminent bypass; (2) recover **variable costs** plus a reasonable contribution to fixed costs; and (3) in instances involving affiliates, was at arm's length and flexes rates no lower than necessary to meet relevant competition.

I. Sales and Transportation Contracts

MGE proposes that a single form of contract be used rather than two forms. MGE states the use of one form does not preclude a customer from taking sales service, transportation service or both. MGE proposes a reduction in the notice requirement from one year to 180 days with regard to customer switches from sales to transportation service

Staff adeptly demonstrates that one effect of MGE's proposal would be the imposition of a maximum daily firm sales requirement which would limit the availability of gas before sales customers incur charges for unauthorized service. (Ex. 28, p. 27). In addition, Staff states that MGE's proposed modification of Section 1.5 of the current tariff would allow MGE to waive metering and telephone line installation charges at its discretion. Id.

***38** The Commission will not approve MGE's proposal to eliminate its 'form of contract' on tariff sheets 32 and 35 on the basis of Staff's argument.

J. Standby Sales Service

The Commission will not authorize MGE to provide this service because MGE has not demonstrated that it can purchase the additional upstream capacity needed to provide the service. (Ex. 28, p. 29).

K. As-Available Sales Service, and L. Unauthorized Use Charges

MGUA, UMKC/JACOMO/CMSU, and Mountain Iron are all transporters of natural gas. These parties have expressed concerns about MGE's proposal in this case. During the course of the hearing MGE witness Langston and Staff witness Hubbs prepared a document marked Exhibit 156 which has been received into the record. Exhibit 156 reflects agreement by Staff and MGE on the issues of the Curtailment Plan (issue 7.5), As-Available Sales Service (issue 7.11), and Unauthorized Use Charges (issue 7.12).

The Commission has reviewed the portions of transcript relating to Exhibit 156 and finds that the contents of Exhibit 156 reflect a reasonable resolution of issues 7.5, 7.11 and 7.12. (Tr. 1514-1550, 1562-1567).

MGUA has asserted that MGE has misapplied its own tariff provisions. If MGUA or any other transporter believes that it has been harmed by a misapplication of MGE's tariffs, such transporter may file a complaint with the Commission. In fact, Mountain Iron has filed such a complaint (Case No. GC-96-372).

M. Financing Advance for Construction

MGE states that this issue has been resolved. To implement the resolution, MGE will submit, as part of its compliance tariffs, tariff language which is similar to that contained in the direct testimony of Staff witness Flowers. (Ex. 83, pp. 14-15; Tr. 1707-1708).

No Party has stated opposition to Staff's proposed tariff language. This issue has been resolved.

N. Service Initiation Charge

MGE has proposed to levy a service initiation charge in the amount of $20.00. MGE contends that it has provided documentation of the costs. (Ex. 31, Sch. DSG-1). MGE asserts that it costs MGE $27.49 to perform the services necessary for a connection or reconnection of service.

OPC maintains that MGE failed to provide support for the proposed charges despite numerous data requests from OPC.

Staff recommends that the Commission reject MGE's proposal to levy a $20.00 service initiation charge. Staff witness Flowers testified that no other Missouri utility companies have such a charge and that MGE was unable to explain to Staff how this proposed charge was determined. Also, Staff witness Flowers testified that if the Commission decides to approve a service initiation charge, then the monthly customer charge should reflect removal of these costs because these costs are 'presumably now recovered from the customer charge.' (Ex. 83, p. 17).

The Commission has reviewed Schedule DSG-1 attached to Gillmore's rebuttal testimony. The Commission finds that this schedule does not provide adequate support for implementation of the $20.00 service initiation charge. Thus, this proposal is rejected.

O. Clarification of Definitions

***39** MGE states that this issue has been resolved and to implement the resolution, the Commission should order MGE to file, as part of its compliance tariff filing, a sheet containing the text of Exhibit 160.

Staff witness Flowers states that MGE's proposed definitions of customers needed clarification. (Ex. 83, p. 18). Staff states that it is willing to accept Exhibit 160 in resolution of the issue, and, since no other party took a position on this issue, this should resolve the matter.

The Commission finds that this matter has been resolved and MGE should file, as part of its compliance tariff filing, a sheet containing the text of Exhibit 160.

P. Levelized Payment Plan

MGE states that this issue has been resolved and to implement the resolution, the Commission should order MGE to file as a part of its compliance tariff filing a sheet containing the text of Exhibit 161. (Tr. 1709).

Staff states that it is willing to accept Exhibit 161 in resolution of this issue.

JACOMO/CMSU/UMKC support the position of the Commission Staff. No other party expressed a position on this issue.

The Commission finds that this matter has been resolved and MGE should file, as part of its compliance tariff filing, a sheet containing the text of Exhibit 161.

Q. Unbundling of Transportation Services

MGE states that no further unbundling of services beyond what it has proposed in this case is appropriate at this time.

MGUA opposes unbundling under the terms proposed by MGE. MGUA maintains that all transportation customers should be provided access to the system on a nondiscriminatory basis. In this proceeding, MGE has argued that EGM is not needed for LGS customers that transport their own gas. MGUA argues that if EGM is not required for LGS customers, then perhaps EGM should not be required for any transportation customers.

The EGM issue was fully litigated in GO-94-318 (Phase I), and in that decision the Commission explained why it agreed with Staff that EGM should be required for transportation customers.

JACOMO/CMSU/UMKC maintain that the cost of providing transportation service should be broken down into its components. They argue that transportation customers should be allowed to purchase only the services that they request and not be required to buy a bundle of services, many of which are unneeded, in order to get the services they desire.

Staff's position is that no party to this proceeding, including MGE, has proposed unbundling of services with sufficient particularity to enable the Commission to order unbundling based on the record before it. Staff opposes unbundling of transportation services based on the record in this case.

The Commission will not authorize the implementation of unbundling as proposed by MGE because MGE's proposal is not supported by adequate evidence of sufficient safeguards for affected customer classes. MGE argues that the Commission should authorize transportation for LGS customers without the balancing benefits of EGM because LGS volumes are smaller than LVS volumes. The Commission will not adopt MGE's proposal based on the record before it. Furthermore, to achieve the Commission's approval MGE's proposal must include evidence of sufficient safeguards for affected customer classes.

R. Disputed Bill Provision

***40** MGUA, JACOMO/CMSU/UMKC and Mountain Iron contend that the Commission should order MGE to implement a 'disputed bill' provision for transportation customers. MGE opposes inclusion of this language for several reasons, arguing that there has never been a demonstrated need for this type of provision.

The Commission has mandated a set procedure for bill disputes involving residential customers (4 CSR 240-13), which is reflected in the tariffs of every gas, water, electric and sewer company regulated by the Commission. MGE maintains that transportation customers do not need the level of protection afforded residential customers because they are capable of 'fending for themselves.' (Ex. 32, p. 22). MGE further argues that the ability of transportation customers to file a complaint against MGE before the Commission with respect to disputes gives MGE an incentive to resolve disputes. MGE references actions it took in connection with a pending complaint case filed by Mountain Iron (GC-96-372). MGE further argues that if the Commission favors disputed bill provisions for nonresidential customers, it should consider it on an industry-wide basis by proposing an amendment to 4 CSR 240-10.040 so all interested parties have an opportunity to comment. MGE points out that the proposed language requires submission of disputes for private arbitration.

Staff agrees with MGE that commercial and industrial customers already have adequate protection in this regard. (Ex. 31, p. 18).

The Commission finds that it would not be appropriate to order MGE to implement a disputed bill provision for nonresidential customers because MGUA's proposal contemplates tariff language that permits submission of these disputes for private arbitration, which would cause a conflict between the Commission's complaint jurisdiction (Section 386.390, R.S.Mo. (1994) and 4 CSR 240- 2.070) and the tariff provisions. If this type of requirement is appropriate, it should be promulgated through a formal rulemaking procedure, not in a company-specific rate case.

S. Payment of Interest on Customer Funds Held by Company

JACOMO/CMSU/UMKC recommend that the Commission require MGE to amend its tariff to require MGE to pay interest on refunds due to overcharges. JACOMO/CMSU/UMKC argue that if MGE realized it may have to pay interest on overcharges, it may be more inclined to resolve bona fide disputes more expeditiously. They contend that without a disputed bill provision or a requirement to pay interest, customers are not on a level playing field when it comes to resolving bona fide disputes. Mountain Iron supports JACOMO/CMSU/UMKC on this issue.

MGE maintains that there is no evidence of any intentional overcharges to warrant JACOMO/CMSU/UMKC's proposal. MGE further contends that a requirement that MGE pay interest on refunds due to overcharges will increase the cost of service ultimately borne by the body of ratepayers.

Staff took no position on this issue.

The Commission finds that the evidence does not support a conclusion that overcharges have occurred with regard to CMSU. The Commission finds that the record before it does not justify implementation of interest charges on overcharges.

T. Refund of Costs of Electronic Meters

***41** JACOMO/CMSU/UMKC and Mountain Iron propose that the Commission order MGE to change its tariff to provide a refund of EGM charges in the event that tariff changes make it uneconomical for a customer to continue transportation service. These parties argue that transportation customers who rely on MGE's previous tariff should not be penalized because MGE decides to change the tariff and, therefore, these transportation customers should receive a refund.

MGE states that the Commission has already turned back attempts in Case No. GO-94-318 to eliminate the requirement of EGM. MGE states that the potential transportation customer makes a business decision as to whether to take transportation service or be a sales customer of MGE. The $5,000 cost of EGM is not held by MGE. These funds are spent to cover the meter installation costs for that customer. MGE states that if the Commission were to rule that after the equipment is installed, MGE will have to refund these amounts when a customer switches back to sales service, it will be an expense for MGE not presently reflected in costs and to the extent MGE is allowed to recover the expense in future rates, it will have to be borne by other customers.

Staff states that no party has alleged that MGE charged more than allowed under its approved tariff. Staff maintains that the imposition of a required refund would be of questionable validity and could be construed as a prohibited retroactive adjustment.

The Commission reiterates that EGM for transportation customers is an essential component of a properly functioning market with regard to multiple entities using MGE's system to transport gas because EGM provides data to MGE to ensure that transporters are in balance.

Certain classes of natural gas customers may decide to be a transportation or sales customer. The cost to install EGM is properly borne by the transportation customers for whom the EGM equipment is necessary. The Commission finds in favor of MGE and Staff on this issue.

U. Shipper Trading

The Commission fails to discern any proposed benefit to MGE or its gas users by implementation of a shipper trading proposal similar to that stated in the Hearing Memorandum.

Implementation of the proposal would violate the burner-tip balancing agreement between Williams Natural Gas Company (WNG) and MGE. Furthermore, as demonstrated by MGE witness Gillmore, implementation of this proposal would result in system control being transferred from MGE to a group of shippers. The system control must remain in the hands of MGE. (Ex. 32, p. 31.) Approval of Mountain Iron's shipper trading idea would be, in all probability, an abdication by the Commission of its duty to ensure safe and adequate service by gas corporations. Section 393.130.1, R.S.Mo. (1994). Finally, the Commission sees no competent and substantial evidence in the record to support the shipper trading idea.

For all these reasons, the Commission will not order implementation of the shipper trading idea.

VIII. Certificated Areas

***42** MGE has committed to file tariff sheets with metes and bounds descriptions and maps showing certificated service areas in the State of Missouri by February 28, 1997. (Tr. 1738-1739). This commitment by MGE adequately addressed Staff's concern on this issue. (Staff Initial Brief, p. 183).

The Commission finds that this issue is resolved by virtue of MGE's commitment to file the requested tariff sheets by February 28, 1996.

Conclusions of Law

The Missouri Public Service Commission has arrived at the following conclusions of law.

Missouri Gas Energy, a division of Southern Union Company, is an investor- owned public utility engaged in the provision of natural gas service in the state of Missouri and, therefore, subject to the jurisdiction of the Missouri Public Service Commission under Chapters 386 and 393, R.S.Mo.

IT IS THEREFORE ORDERED:

1. That pursuant to the findings of fact and conclusions of law in this Report And Order, the proposed tariff sheets filed by Missouri Gas Energy, a division of Southern Union Company, on March 1, 1996 are hereby rejected.

2. That pursuant to the findings of fact and conclusions of law in this report And

Order, the proposed substitute tariff sheets filed by Missouri Gas Energy, a division of Southern Union Company, on March 11, 1996 are hereby rejected.

3. That Missouri Gas Energy, a division of Southern Union Company, is hereby authorized to file, in lieu of the rejected tariff sheets, for approval of the Commission, tariff sheets designed to increase gross revenues, exclusive of any applicable license, occupation, franchise, gross receipts taxes, or other similar fees or taxes, by the amount of $7,527,513 for natural gas service rendered in its Missouri service area on an annual basis over its current revenues.

4. That the tariffs sheets to be filed pursuant to this Report And Order shall become effective for natural gas service rendered on and after February 1, 1997.

5. That the Stipulation And Agreement filed by Missouri Gas Energy, the City of Kansas City, Missouri, the Office of the Public Counsel and the Commission's Staff on October 30, 1996, relating to an experimental weatherization program and the Amendment thereto filed on January 3, 1997 are hereby approved. (Attachments A and B, respectively).

6. That Case No. GC-96-402 be closed pursuant to the terms of Attachment C.

7. That the Stipulation And Agreement filed by the Midwest Gas Users Association, University of Missouri-Kansas City, Central Missouri State University, Jackson County, Missouri, the Office of the Public Counsel and the Commission's Staff on October 30, 1996, relating to class cost of service and related revenue shifts, is not approved.

8. That the Motion For Variance From Protective Order filed by Missouri Gas Energy, a division of Southern Union Company, on October 17, 1996 is hereby granted.

9. That the Supplement to Exhibit 111 filed by Missouri Gas Energy, a division of Southern Company, on January 3, 1997, be received into the record.

10. That the Motion For Admission Of Late-Filed Exhibit filed by Missouri Gas Energy, a division of Southern Company, on January 6, 1997, be denied.

11. That late-filed Exhibits 113, 114, 115, 116, 117, 120, 163, 163HC, 164, 171, 172, 173, 174, 179 and 179HC be received into the record.

12. That the completed Revenue Requirement Scenario filed on January 10, 1997 shall be received into the record as Exhibit 180 (Attachment E).

13. That those motions and objections not specifically ruled on in this order are hereby denied or overruled.

14. That this Report And Order shall become effective on the 1st day of February, 1997.

***43** (SEAL)

Dated at Jefferson City, Missouri, on this 22nd day of January, 1997.

Attachment A

Stipulation and Agreement

The undersigned parties have reached agreement on the following general principles of settlement to resolve the issue denominated as Experimental Weatherization Program in the Hearing Memorandum in this proceeding and to provide for the dismissal with prejudice of the complaint of the Office of the Public Counsel in GC-96-402.

I. REVENUE COMMITMENT

The Company is agreeable to providing $250,000 annually for this program so long as the Commission will include a $250,000 amount specifically for the program in the revenue requirement in this case. As long as that amount is included in the rate level authorized for Missouri Gas Energy, MGE will provide that amount to the City of Kansas City annually. The stipulation and agreement will contain a provision that reads substantially as follows:

The parties agree that the Commission should include a $250,000 amount for the experimental weatherization program in Case No. GR-96-285. So long as that amount is included in the rate level authorized for MGE, MGE will provide that amount to the City of Kansas City annually (the program funds) for the weatherization grant and loan program. The parties agree that the program should continue for a period of at least two years from February 1, 1997. MGE's obligation to provide the $250,000 annual payment ceases when that amount is no longer reflected in the rate level authorized by the Commission.

II. PROPOSED TARIFF

EXPERIMENTAL WEATHERIZATION PROGRAM

Description and Availability: In accord with this tariff, and pursuant to the terms and conditions of a stipulation and agreement (pertaining to the experimental weatherization program) filed and approved in Case No. GR-96- 285, the Company will provide $250,000 annually (the program funds) for an experimental residential weatherization grant and loan program, including energy education, primarily for lower income customers. The program will be administered by the City of Kansas City, Missouri pursuant to a written contract between the City and MGE which will take effect after it is approved by the Commission. MGE and the City will consult with Staff and Office of the Public Counsel prior to execution of the contract and its submission to the Commission. While it is experimental, the program will be limited to existing low-income to middle-income (as defined by the Office of Management & Budget (OMB)), Missouri Gas Energy (MGE) residential customers within Clay, Platte, and Jackson Counties in Missouri.

Purpose: This program is intended to assist customers through conservation, education and weatherization in reducing their use of energy and to reduce the level of bad debts experienced by the Company.

Terms and Conditions: Unless specifically exempted in any of the following terms and conditions the following terms and conditions, at a minimum, shall be included in any agreement between MGE and the City of Kansas City concerning administration of the program.

***44** 1. The program will offer a combination of grants and interest rate subsidies based upon the eligible customer's income and family size. The program will be primarily directed to lower income customers with high usage and/or bad debts. 2. The total amount of loans and grants offered to a customer will be determined by the cost-effective improvements that can be made to a customer's residence, which shall not exceed $3,000, and is expected to average $1,750. 3. Program funds cannot be used for administrative costs except those incurred by the City of Kansas City that are directly related to qualifying and assisting customers under this program. The amount of reimbursable administrative costs per participating household shall not exceed $300 for each participating household. 4. Loans to customers under this program will be administered by participating banks. In no event shall a customer's performance with respect to a loan under this paragraph be used as a basis for receiving or continuing utility service from the Company. The Company shall not be required to buy back or otherwise pursue collection on the non-performing loans. 5. The City of Kansas City and the Company both agree to consult with Staff and Public Counsel (and any other party agreeable to Company, Staff, Public Counsel and the City) during the term of the program. 6. A Program participant's bill will not be calculated using an estimated meter read. If the Company regularly experiences difficulties obtaining regular meter reads, the Company will install on the meter and utilize a remote reading attachment. Notwithstanding the general terms and conditions for gas service, tariff sheet numbers R-41 and R-42, Section 5.05, the attachments shall be installed with an initial installation cost as specified in those sheets to be recovered by the Company from program funds. The currently approved amount is $50. The initial installation cost will be a deduction to any payment due the City of Kansas City pursuant to the aforesaid agreement. The Company shall not utilize program funds to recover other costs of remote meter reading devices. The Company will provide documentation to the City of Kansas City on any such installations. 7. This program will continue until the effective date of an order of the Commission in the Company's next general rate case, unless otherwise ordered by the Commission. With the primary assistance of the City of Kansas City, the Company shall submit a report on the program to the Staff, and Public Counsel on or before April 15, 1998 and on the same date in 1999 and for each succeeding year in which the program continues. Each report will address the progress of the program, and provide an accounting of the funds received and spent on the program by the City. The report shall be subject to audit by the Commission Staff and Public Counsel. To the extent that $250,000 exceeds the total cost expended by the City on the program, the amount of the excess shall be 'rolled over' to be utilized for the weatherization program in the succeeding year, excepting that if there is an excess at the time the program terminates, the amount of excess shall be transmitted to MGE. MGE thereafter shall credit the amount of the excess to its refund account under the experimental gas cost incentive mechanism and flow that excess back to ratepayers under that mechanism. To the extent that there is any 'excess' resulting from the supplemental payments by the Company of the $140,000 referred to herein, those amounts shall be refunded in the same manner.

***45** Each of the above-referenced reports shall contain the following information about each home weatherized. The party responsible for the preparation of the information is designated in parentheses by each item. KC refers to the City of Kansas City and MGE refers to the Company.

A. Demographics

1. Customer name (KC, to be verified by MGE) 2. MGE account number (MGE) 3. Home and work phone number (KC, to be verified by MGE) 4. Street address, city, county, zip (KC, to be verified by MGE) 5. Gross monthly income (KC) 6. Type of income (social security, wages, other) (KC) 7. Family size (KC)

a. Number of elderly over 60 (KC) b. Number of disabled (KC) c. Number of children under 5 (KC)

8. Type of dwelling unit (KC) 9. Number of rooms (KC)

B. Gas Usage (MGE)

1. Actual usage history two years prior to weatherization (reported monthly). (MGE) 2. Identify actual monthly usage after weatherization for at least 24 months. (MGE)

C. Payment History (MGE)

1. Billed dollars (MGE) 2. Arrears dollars (MGE) 3. Payment history, including payment history codes (D, R, N, L, P, etc.) (MGE)

D. Weatherization Cost for Each Program Participant (KC)

1. Initial visit date (KC) 2. Audit date (KC) 3. Write bid date (KC) 4. Complete bid date (KC) 5. Award bid date (KC) 6. Weatherization date (KC) 7. Technical assistance (KC) 8. Installer cost (KC) 9. Supplemental funding for contract costs (Sources specified) (KC) 10. Total costs of D. (KC)

E. Education (KC)

1. Specify and describe education program (KC) 2. Report education provided to individual participants (KC)

F. Contractor Invoices (KC)

8. MGE will grant City access to program-required customer information in connection with the preparation and submission of these reports to the extent participants consent to the provision of the information. The Company, with data or reports provided by the City of Kansas City, shall also submit a report to Staff and Public Counsel reporting weatherization activity each quarter.

This report will be due on the tenth calendar day of the second month following the quarter for which weatherization activity is being reported. The first quarter subject to this reporting requirement shall be the quarter beginning April 1, 1997.

Each quarter update report shall contain:

A. Total homes weatherized at beginning of quarter and during quarter; B. Total homes in progress at end of quarter; C. Expenditures per program participant; and D. Total monies spent on program.

9. An independent consultant selected by the City of Kansas City, and the Company, with concurrence of Public Counsel and Staff, will evaluate the cost effectiveness of the Program. The consultant's services shall be governed by a written contract and the scope of work in the contract will include, but will not be limited to, those matters listed below:

A. Impact of energy usage

1. Weatherization measures 2. Education

B. Impacts of weatherization and education

1. Changes in energy usage (gas and electric) and corresponding energy costs. 2. Changes in comfort, safety, etc. 3. Changes in bad debt expense, collection expense, etc.

***46** The Company will award the contract, with consent of the City, the Staff and Public Counsel, on or before February 1, 1997 unless such deadline is extended by the Commission for good cause shown. If a decision as to the awardee for the contract is not finalized by February 1, 1997, or the date to which the award date has been extended, the Commission may, at its option select the consultant.

The Company, with the assistance of the City of Kansas City, shall continue to collect data for this group of participants and any additional participants of the plan for 24 months after termination of the experimental weatherization program. At that point, the Company, with the assistance of the City of Kansas City, will provide weather normalized gas usage for each participant of the program. The Company shall utilize the weather normalization method utilized by the Commission in Case No. GR-96-285.

10. MGE will provide the City or the consultant on a timely basis all information within its possession, custody or control that is necessary for the preparation of the reports and studies required by the contract between the City and MGE or MGE and the consultant. MGE will retain final responsibility for submittal of the report(s), required for submittal under this tariff but is not responsible for any failure of the City of Kansas City to provide data in the possession of the City. MGE shall provide appropriate notices to the City of Kansas City as to the applicable deadlines for the reporting to the Commission and provide copies of such reminder letters to Staff and Public Counsel. 11. MGE and City Agreement: Staff, Public Counsel, the City and MGE agree that any controversy, complaint, claim or dispute arising out of or relating to the agreement between the City and MGE shall be settled by compulsory arbitration before the Commission. Staff, Public Counsel, the City or MGE may file a request for such arbitration in accord with Commission rules or an agreed upon procedure. If no procedure is provided in the rules or agreed to within 30 days of the request, then the same shall be governed by the rules of the American Arbitration Association. Pending the outcome of the arbitration, and unless otherwise ordered by the Commission, MGE may withhold from the City so much of the

program fund installment(s) owed under the agreement that are relevant to the dispute, or otherwise so much of the program funds that will protect MGE's interests.

III. Dismissal of the Complaint

The parties agree that in return for the following promise by MGE, the Public Counsel shall dismiss its complaint in GC-96-402 with prejudice: MGE agrees to augment the monthly amount as provided by in the tariff sheet by contributing additional monthly payments in equal amounts over 36 months for a total supplemental payment of $140,000. The consultant contract payments will then be deducted from the total program amount.

IV. Representation by City of Kansas City

The City of Kansas City represents that it will timely provide the information and reports set forth in the tariff, the contract between the City and MGE, and in this agreement.

V. Other Provisions

***47** This Stipulation and Agreement has resulted from extensive negotiations among the signatories and the terms hereof are interdependent. In the event the Commission does not approve and adopt this Stipulation and Agreement in its entirety, then this Stipulation and Agreement shall be void and no signatory shall be bound by any of the agreements or provisions hereof. None of the signatories to this Stipulation and Agreement shall have been deemed to have approved or acquiesced in any ratemaking or procedural principle, any method of cost determination or cost allocation, or any service or payment standard, and none of the signatories shall be prejudiced or bound in any manner by the terms of this Stipulation and Agreement in this or any other proceeding, except as otherwise expressly specified herein. Respectfully submitted, Gary W. Duffy MBE #24905 Brydon, Swearengen & England P.C. P.O. Box 456 Jefferson City, Missouri 65102-0456 Attorneys for MGE Douglas E. Micheel MBE #38371 Office of the Public Counsel P.O. Box 7800 Jefferson City, MO 65102 Attorney for the Office of the Public Counsel Thomas R. Schwarz, Jr. MBE #29645 Senior Counsel Missouri Public Service Commission P.O. Box 360 Jefferson City, MO 65102 Attorney for the Staff of the Missouri Public Service Commission Mark W. Comley Newman, Comley and Ruth P.C. 205 East Capitol Avenue Jefferson City, MO 65102 Attorney for the City of Kansas City

Attachment B

AMENDMENT TO STIPULATION AND AGREEMENT

The interested parties to the issue denominated as Experimental Weatherization Program in the Hearing Memorandum in this proceeding entered into and filed with the Commission a Stipulation and Agreement to resolve this issue and to provide for the dismissal with prejudice of the complainant of the Office of the Public Counsel in GC-96-402.

Paragrah 9 of the Proposed Tariff included within the Stipulation and Agreement provided that a consultant would be retained by MGE by February 1, 1997. It is been agreed by the parties to the Stipulation and Agreement that the date for the award of contract provided for in paragraph 9 of the Proposed Tariff should be extended until May 1, 1997.

Therefore, the Stipulation and Agreement is hereby amended to extend the date of award of the consultant contract in Paragraph 9 of the Proposed Tariff from February 1, 1997 to May 1, 1997.

All other provisions of the agreement shall remain unchanged. Respectfully submitted, Gary W. Duffy MBE #24905 Brydon, Swearengen & England, P.C. P.O. Box 456 Jefferson City, Missouri 65102-0456 537/635-7166 ATTORNEY FOR MGE Mark W. Comley, MBE #28847 Newman, Comley and Ruth P.C. 205 East Capitol Avenue Jefferson City, Missouri 65102 573/634-2266 ATTORNEY FOR THE CITY OF KANSAS CITY R. Blair Hosford, MBE #21775 Assistant General Counsel Thomas R. Schwarz, MBE #29656 Senior Counsel Missouri Public Service Commission P.O. Box 360 Jefferson City, MO 65102 573/751-8702 ATTORNEYS FOR THE STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION Douglas E. Micheel, MBE #38371 The Office of the Public Counsel P.O. Box 7800 Jefferson City, Missouri 65102 573/751-5560 ATTORNEY FOR THE OFFICE OF THE PUBLIC COUNSEL

CERTIFICATE OF SERVICE

***48** I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record as shown on the attached service list this 3rd day of January, 1997. Signature

Attachment C

Stipulation and Agreement

The undersigned parties have reached agreement on the following general principles of settlement to resolve the issues of Cost of Service and the related revenue shifts which resolves issues 6.1.1 Allocation of Costs for Services, Meters, and Regulators; 6.1.2 Allocation of Costs for Mains; 6.1.3 Class Cost of Service Results; and 6.2.4 Class Rate Increases as delineated in the Hearing Memorandum filed in this proceeding. This Stipulation does not include Issue 6.2.2 Customer Charges. The parties reserve the right to cross examine witnesses on the issues settled in this Stipulation and Agreement for the limited purpose of the use of those costs in the customer charges and not to question witnesses on the settled issues.

COST OF SERVICE CLASS REVENUE SHIFT

The parties agree that the cost of service class revenue shift issue will be settled in the following manner:

a. If the Commission determines that the revenue requirement increase should be at the Staff's midpoint ($6,096,685) in the revised reconciliation from October 18, 1996 then prior to any rate increase the following class revenue shifts will be made: $1,788,727 will be shifted to the residential class and the sum of the revenues for all other classes combined will decline by this amount. Any revenue shifts from the other classes made possible by the increase to the residential class will be spread among the non-residential classes so that their class revenue requirements decrease by equal percentages. b. If the Commission determines that the revenue requirement increase should be some amount greater than $6,096,685 then the revenue shift to the residential class will decrease by one fifth of the revenue requirement increase above $6,096,685 to, but not beyond, the point where the shift to residential class becomes zero. If the Commission determines that the revenue requirement increase should be some amount less than $6,096,685 then the revenue shift to the residential class will increase by one fifth of the difference between the Commission determined revenue requirement and $6,096,685 to, but not beyond, the point where the revenue requirement change becomes zero. c. In the event that the Commission determines that MGE did not meet the condition specified in paragraph 7 of the Stipulation and Agreement approved in Case No. GM-94-40 for filing a rate case, then no class revenue shift shall be made in this docket. This agreement reflects the rate impact concerns shared by all of the undersigned parties.

OTHER PROVISIONS

This Stipulation and Agreement has resulted from extensive negotiations among the signatories and the terms hereof are interdependent. In the event the Commission does not approve and adopt this Stipulation and Agreement in its entirety, then this Stipulation and Agreement shall be void and no signatory shall be bound by any of the agreements or provisions hereof. None of the signatories to this Stipulation and Agreement shall have been deemed to have approved or acquiesced in any ratemaking or procedural principle, any method of cost determination or cost allocation, or any service or payment standard, and none of the signatories shall be prejudiced or bound in any manner by the terms of this Stipulation and Agreement in this or any other proceeding, except as otherwise expressly specified herein.

***49** In the event the Commission accepts the specific terms of this Stipulation And Agreement, the parties waive their respective rights to cross- examine witnesses and to present oral argument and written briefs pursuant to Section 536.080.1 RSMo 1994; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2 RSMo 1994; and their respective rights to judicial review pursuant to Section 386.510 RSMo 1986. In the event that the Commission does not accept this Stipulation and Agreement, the undersigned parties believe it would be appropriate to conduct cross-examination and to brief this issue in order to develop a full record on which the Commission can base its decision. Respectfully submitted, Penny G. Baker Missouri Bar No. 34662 P.O. Box 360 Jefferson City, MO 65102 573/751-6651 573/751-9285 (fax) ATTORNEY FOR THE MISSOURI PUBLIC SERVICE COMMISSION Stuart W. Conrad Missouri Bar No. 23966 3100 Broadway Kansas City, MO 64111 816/753- 1122 816/756-0373 (fax) ATTORNEY FOR THE MIDWEST GAS USERS ASSOCIATION Douglas E. Micheel Missouri Bar No. 38371 P.O. Box 7800 Jefferson City, MO 65102 573/751-5560 573/751-5562 (fax) ATTORNEY FOR THE OFFICE OF THE PUBLIC COUNSEL Jeremiah Finnegan Missouri Bar No. 18416 3100 Broadway, Suite 1209 Kansas City, MO 64111 816/753-1122 816/756-0373 (fax) ATTORNEY FOR UNIVERSITY OF MISSOURI- KANSAS CITY, CENTRAL MISSOURI STATE UNIVERSITY AND JACKSON COUNTY, MISSOURI

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed or hand- delivered to all counsel of record as shown on the attached service list this 30th day of October, 1996.

Attachment D

For immediate release October 21, 1996

The Federal Reserve Board today approved the use of certain cumulative preferred stock instruments in Tier 1 capital for bank holding companies.

These instruments, which are marketed under a variety of proprietary names such as MIPS and TOPRS, are issued out of a special purpose subsidiary that is wholly owned by the parent company. The proceeds are lent to the parent in the form of a very long-term, deeply subordinated note.

Bank holding companies seeking to issue such securities should consult with their District Federal Reserve Bank. Such arrangements, which give rise to minority interest upon consolidation of the subsidiary with the parent holding company, normally will be accorded Tier 1 capital status. Minority interest in consolidated subsidiaries generally qualifies as Tier 1 capital under the Board's current capital adequacy guidelines for bank holding companies.

To be eligible as Tier 1 capital, such instruments must provide for a minimum five-year consecutive deferral period on distributions to preferred shareholders. In addition, the intercompany loan must be subordinated to all subordinated debt and have the longest feasible maturity.

The amount of these instruments, together with other cumulative preferred stock a bank holding company may include in Tier 1 capital, is limited to 25 percent of Tier 1. Like other preferred stock includable in capital, these instruments require Federal Reserve approval before they may be redeemed.

Attachment E

***50** REVENUE REQUIREMENT SCENARIO RECONCILIATION

Jefferson City, Missouri January 10, 1997

General Notes

1. The value of each rate base issue has been calculated using grossed-up for tax rates of return based on the various rates of return specified in the Commission scenario request. The grossed-up rates are 11.50%, 11.79%, 12.08%, and 12.31% based on OPC's recommended ROE, Staff's low end, Staff's midpoint and MGE's ROE, respectively. 2. The value of Item #30 Rate of Return is calculated using MGE's rate base and the grossed-up rates of return noted in footnote 1 above. 3. Starting from a Company position of $34,390,502 allows for recovery in rates of $659.137 in what has previously been referred to as unreconciled differences. Each party's position regarding this issue is discussed in recently filed motions before the Commission. If the Commission accepts Staff's position, $659,137 must be removed from the revenue deficiency on all revenue requirement calculations shown on the Scenario sheet. If the Commission accepts MGE's position, the revenue requirement calculations are correct as shown.

MGE Notes to Response to Commission Revenue Requirement Scenario

1. The Staff has provided the Commission with two alternatives on the carrying cost rate, alternatives which affect items 22 and 25.

a. The first alternative is the Company's AFUDC rate. The revenue requirement impact is shown on the attached scenario sheet in items 22 and 25. This recommendation would require MGE to write-off $5,990,333 of previously reported earnings. b. A second alternative is to use the Company's approved rate of return in this case and the AFUDC rate on a going-forward basis.

As stated in Staff's initial brief, 'In the alternative, if the Commission wishes to avoid a major write-off by MGE, but otherwise agrees with Staff's position on this issue, the Staff recommends the Commission order the Company's approved rate of return in this case as the deferred carrying charge for the construction in this proceeding and the Company's AFUDC rate as the deferred carrying charge on a prospective basis' (Staff Initial Brief, pp. 101-102). The following table provides quantification of the revenue deficiency effect of Staff's alternative recommendation. The table shows the alternative adjustment that would be appropriate for lines 22 and 25 in the Scenario sheet attached. In addition, the line 'Required earnings write-off' is the amount of MGE's previously reported earnings that would have to be written off depending on which carrying cost rate is approved by the Commission.

		Alternative Carrying Cost Rates (Underlying ROE in parenthesis)			
	AFUDC	9.28% (10.75%)	9.46% (11.3%)	9.64% (11.83%)	9.78% (12.25%)
Revenue Effects of Differences between Company's Current Position and Scenario					
Item 22 Income Tax adjustment-Nondeductible Sheet SLRP	Scenario (245,699)	(254,805)	(263,941)	(271,048)	
Item 25 Carrying Cost	Scenario Sheet	(146,630)	(128,784)	(109,878)	(94,475)
Required Earnings write-off	(5,990,333)	(1,729,064)	(1,517,645)	(1,306,229)	(1,141,785)

***51** 2. MGE agrees with OPC Notes 1 and 2.

OPC Notes to Response to Commission Revenue Requirement Scenario

1. Item #32 -- Advertising.

Footnote B. The correct amount of duplicate Smith Grieves is $4,546.57, not $4957.69. Footnote D. The Commission Scenario calls for excluding 7/8ths of $16,862.93 expense for TNT, Inc. charges. The OPC adjustment recommended disallowance of 7/8ths of $19,271.91, which is $16,862.93. If the intent was to adopt OPC's recommendation, the revenue requirement should be reduced by $2,614.

OPC recommended disallowance (Scenario footnote D) $19,272

Multiply by 7/8ths	87.5%
Net disallowance	$16,863
Amount previously removed by Staff and MGE	($14,249)
Net decrease in revenue requirement	$2,614

Footnote E. The revenue requirement should be further reduced by only $872.93 because Staff has previously removed $4,162.64 of the $5,035.57. OPC believes the correct amount of Item #32-Advertising in the Scenario should be: $15,094 as shown below:

Footnote B	($ 4,547)
Footnote D	($ 2,614)
Footnote E	($ 873)
Footnote F	($ 7,060)
Total Item 32	($15,094)

2. Item #35 -- Polsinelli & White Charges. Of the $22,056.11 at issue MGE agreed that $11,509.26, which was related to its investigation of an appliance financing program, should be excluded from the revenue requirement (Tr. p.910 lines 2-13). Therefore, Public Counsel believes the Scenario should reflect a reduction for the appliance financing program investigation. Thus, $10,546.85 was the remaining issue, of which only $4,039.58 dealt with the KPP monitoring.

Staff Notes to Response to Commission Revenue Requirement Scenario

1. The Company starting point of $34,390,502 is more than the Company's request in its original revenue requirement filing. 2. The scenario showing Staff's midpoint return on equity is based on 11.83% as requested by the ALJ. Staff had previously used 11.80% as its midpoint return on equity in all revenue requirement filings in this case. 3. Staff received the Company's workpapers supporting their calculations in MGE Note 1 above on January 10, 1997 and has not had sufficient time to verify these calculations. 4. The Staff agrees with OPC's position in OPC Notes 1 and 2 above.

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

FOOTNOTE

FN1 United Cities Gas Company, GR-95-160; The Empire District Electric Company, ER-95-279; and Laclede Gas Company, GR-96-193.

END OF DOCUMENT

Re Consumers Power Company
Case No. U-10651

Michigan Public Service Commission
February 23, 1995

ORDER authorizing a natural gas local distribution company (LDC) to enter a special contract for the provision of gas transportation service to an industrial customer at discount rates.

Commission finds that there is an adequate evidentiary basis to conclude that the industrial customer has an economic bypass alternative and that the **special contract** rates are necessary to induce the customer to remain on the LDC system. Moreover, it finds that there is an adequate evidentiary basis to conclude that the rates in the **special contract** will cover the **variable costs** of serving the industrial customer and will provide a contribution to the fixed costs of the LDC system.

Any revenue shortfall created by the difference between the special contract rate and the otherwise applicable tariffed rate floor is the responsibility of shareholders -- i.e., the LDC is prohibited from seeking to recover that shortfall from other customers. However, the potential revenue shortfall created by the difference between the tariff rate floor and the transportation class cost of service will be addressed and resolved in a pending general rate case.

Commission states that it presumes that the LDC negotiated the special contract with a knowledge that it may not discriminate against other similarly situated customers and that it expects the LDC to act in accordance with applicable law. Customers of the LDC are, the commission notes, free to pursue remedies in the event of unlawful discrimination.

Commission rejects a challenge to the legality of a contract provision that exempts the industrial customer from future surcharges that may occur during the five-year term of the contract, again noting that issues concerning discrimination against other customers can be addressed when and if they arise.

Commission finds no basis to disagree with the LDC's assertion that retaining the industrial customer will not affect planned construction during the term of the contract.

For prior order that had required the utility to present additional evidence addressing the cost of serving the special contract customer, the economic feasibility of the customer's bypass option, and the implications of negotiated arrangements for other customers, see Re Consumers Power Co., 159 PUR4th 162 (Mich.P.S.C.1995).

P.U.R. Headnote and Classification

1.

RATES

s166

Mi.P.S.C. 1995

[MICH.] Reasonableness -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Special contract -- Gas transportation service -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

2.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Special factors -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Gas transportation service -- Special contract -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

3.

RATES

s140

Mi.P.S.C. 1995

[MICH.] Reasonableness -- Competition -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Special contract -- Gas transportation service -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

4.

MONOPOLY AND COMPETITION

s58

Mi.P.S.C. 1995

[MICH.] Natural gas -- Anti-bypass discounts -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

5.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Revenue shortfalls -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

6.

REVENUE

s5

Mi.P.S.C. 1995

[MICH.] Natural gas -- Discount transportation service -- Treatment of revenue shortfall -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

7.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- **Special contract** rate -- Anti-bypass discount -- Pricing -- Recovery of **variable costs** -- Contribution to fixed system costs -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

8.

DISCRIMINATION

s26

Mi.P.S.C. 1995

[MICH.] Special contract rates -- Anti-bypass discount -- Legality -- Natural gas local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

9.

DISCRIMINATION

s61

Mi.P.S.C. 1995

[MICH.] Concessions to particular customer -- Large industrial customer -- Special contract rate -- Anti-bypass discount -- Legality -- Natural gas local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

10.

DISCRIMINATION

s109

Mi.P.S.C. 1995

[MICH.] Natural gas rates -- Special contract rate -- Anti- bypass discount -- Legality -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

11.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Legality -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

12.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate

-- Anti-bypass discount -- Pricing -- Exemption from surcharges -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

13.

GAS

s7

Mi.P.S.C. 1995

[MICH.] Natural gas -- Load management -- Special contract rate -- Anti- bypass discount -- Effect on planned construction -- Local distribution company.

Re Consumers Power Company

Before Strand, chairman, and Russell and O'Donnell, commissioners.

BY THE COMMISSION:

OPINION AND ORDER

I.

HISTORY OF PROCEEDINGS

On June 30, 1994, Consumers Power Company (Consumers) and James River Corporation agreed to enter into a special contract for the provision of natural gas transportation service. The rates under the special contract are less than those authorized in Consumers' currently effective transportation tariffs, Rate T-1 and Rate T-2. Consumers says that it found it necessary to offer James River this special contract in order to prevent James River from bypassing the company's system in favor of directly connecting with Panhandle Eastern Pipe Line Company's (Panhandle) pipeline located near James River's Kalamazoo area facilities.

On August 5, 1994, Consumers filed an application for ex parte approval of the special contract, with the pricing terms deleted from the attached copy of the contract. On September 20, 1994, after giving up its efforts to protect the confidentiality of the contract pricing terms, Consumers filed a complete copy of the special contract.

On October 27, 1994, Consumers filed the testimony and exhibits of four witnesses in support of the application. A prehearing conference was held on the same day before Administrative Law Judge James N. Rigas (ALJ). He granted the petitions to intervene filed by James River and Attorney General Frank J. Kelley (Attorney General). Consumers requested an expedited hearing that would have permitted a final Commission order on or before February 3, 1995, because James River had indicated that it would pursue a bypass alternative if the contract were not approved by then. The ALJ set an abbreviated schedule, although not as expedited as Consumers. requested. [FN1]

The Commission Staff (Staff) filed the testimony of one witness on November 23, 1994.

Cross-examination was scheduled to commence on December 14, 1994. On that date, the parties (except James River, which was not present) agreed to an accelerated schedule that included (1) binding in the prefiled testimony with the exception of a portion of the Staff witness's testimony, (2) a waiver of the right to cross-examine the witnesses and a waiver of the right to file rebuttal testimony, (3) the filing of simultaneous briefs and a waiver of the right to file reply briefs, and (4) the submission of the case directly to the Commission with a waiver of Section 81 of the Administrative Procedures Act, dispensing with the need for a proposal for decision. [FN2] The record at that point consisted of 96 pages of transcript and 13 exhibits.

On January 6, 1995, Consumers, the Attorney General, the Staff, and James River filed initial briefs.

On January 17, 1995, the Commission issued an order remanding the case to the ALJ for further development of the record. In response to the Commission's order, Consumers filed supplemental testimony of three witnesses.

The cross-examination of all witnesses occurred on February 1 and 2, 1995. In addition, the rebuttal testimony of David W. Joos, Executive Vice President and Chief Operating Officer of Consumers' Electric Division; Robert Russel, James River's Group Service Manager; and Michael L. Collins, a Gas Cost Recovery Specialist in the Commission's Gas Division, was presented and cross-examined on February 2, 1995.

On February 10, 1995, Consumers, the Attorney General, and the Staff filed supplemental briefs. On February 17, 1995, Consumers, the Attorney General, the Staff, and James River filed reply briefs. Because the Commission read the record or attended the hearings or both, the ALJ did not prepare a proposal for decision. The complete record consists of 496 pages of transcript and 26 exhibits.

Consumers and James River urge the Commission to approve the special contract. The Staff and the Attorney General urge the Commission to reject the special contract.

II.

DISCUSSION

Contract Approval

[1-4] The contract provides a rate of $0.15 per thousand cubic feet (Mcf) for years one through three and a rate of $0.18 per Mcf for years four and five for the two larger James River facilities in the Kalamazoo area. These rates are below the Rate T-2 floor of $0.2367 per Mcf. The company's two smaller facilities would continue to pay the Rate T-1 rate, which is now $0.4734. Current surcharges would apply, but future surcharges would not apply to any of the facilities. James River's annual minimum consumption would be 4 billion cubic feet (Bcf) for years one through three and 2 Bcf for years four and five. Its load balancing would be 8.5% of the minimum volume, and its storage contract would be canceled. The maximum daily quantity would be reduced by almost half.

Consumers offered the testimony of four witnesses in support of its application.

David E. Madden, a Senior Engineer in Consumers' Marketing Department, testified that James River's larger Kalamazoo area facilities are the first and sixth largest users of natural gas on Consumers' system, using more than 4 Bcf per year.

Mr. Madden testified that in September 1992, James River requested that Consumers remove a no-bypass clause from its gas transportation contract. James River wanted to pursue a bypass alternative because the storage available to it had been decreased and it was dissatisfied with the surcharges imposed on Rate T-2 customers.

Negotiations began and the contract was modified in January 1993. In August 1993, James River notified Consumers of its intent to bypass the utility's system. Mr. Madden noted that James River's facilities are located in a manner that would permit James River to build four miles of pipeline along a railroad right-of-way to Panhandle's city gate, which Consumers believed made the bypass economical. Negotiations continued, with James River rejecting two offers made in October 1993.

Mr. Madden testified that James River provided a spreadsheet to Consumers, Exhibit A-5, that showed a savings of $3.8 million from the last quarter of 1994 through 1999 if it bypassed Consumers' system, based on Consumers' October 13, 1993 offer. Based on that exhibit, he testified that Consumers would have had to offer a rate of negative $0.043 per Mcf in 1994 and a rate of $0.135 per Mcf in 1997 to match the economics of the bypass option. On June 28, 1994, Consumers offered James River a five-year special contract with rates below the Rate T-2 floor. James River rejected that offer. On June 30, 1994, Consumers countered with a change to the annual load balancing, and James River accepted.

In his supplemental testimony, Mr. Madden provided additional explanation for some of the figures on the James River spreadsheet and made a correction. He also sponsored Exhibit A-15, which compares James River's gas costs under the bypass alternative, the special contract, and the Rate T-2 floor. He calculated that James River would realize savings of more than $2.5 million if it were to pursue the bypass alternative instead of choosing to stay on Rate T-2 at the floor price. He acknowledged that the special contract requires James River to pay in excess of $1 million more than it would pay for the bypass option, but he believed that James River is willing to pay that price because of the value it places on the company's transportation service. He also testified that he now expects James River's load to remain near 4 Bcf for the full term of the contract, despite James River's right to reduce its annual contract quantity in the last two years. The effect, he said, is to increase the benefits of the special contract for other customers.

Finally, Mr. Madden noted that James River has a facility in Camas, Washington, that bypassed the local utility. He stated that James River would definitely bypass Consumers' system if the Commission did not approve the special contract. He testified that the special contract represents the best bargain that Consumers could obtain and still keep James River as a customer.

Patrick D. Miller, Consumers' Manager of Gas Distribution Services, described the variable distribution costs associated with providing gas transportation service to James River. He explained that the costs include meter installation and maintenance, the odorant added to the gas, and costs associated with leak surveys, leak repairs, staking, operating mains and services, and maintaining adequate cathodic protection. He estimated the total annual variable distribution costs for the two larger James River facilities to be approximately $3,800 per year.

John R. Biek, Consumers' Director of Gas Supply, Planning, and Control, described the effect on the company's gas transmission and storage system from continuing to serve James River. He explained that the only variable transmission and storage costs are compressor station maintenance and the effect on the cost of gas for gas cost recovery (GCR) customers. He estimated the compressor maintenance expense to be approximately $50,000 per year. The GCR effect is due to the authorized tolerance level of 8.5% associated with the special contract. With an annual contract quantity of 4 Bcf, James River is entitled to 340,000 Mcf of authorized tolerance level, which is storage capacity that could potentially be used to benefit GCR customers if James River left the system. The potential effect on the cost of gas for GCR customers is approximately $372,000 annually in the first three years and $236,000 annually in the last two years. That cost represents the estimated higher cost of buying winter gas using firm transportation to deliver the gas directly to GCR customers as opposed to purchasing gas on interruptible transportation and placing it in storage during the summer injection cycle.

James F. Bearman, Rates Director in Consumers' Gas Division, testified that the James River situation represents the first viable bypass threat since the utility's current gas transportation program began in 1989. He argued that a bypass by James River would send a negative competitive signal to other major customers on the system, would result in spreading the fixed costs of the lost load to remaining customers, and might spur further aggressive competitive behavior by interstate pipelines. He noted that National Steel in Ecorse bypassed Michigan Consolidated Gas Company (Mich Con) in 1989 and Escanaba Paper Company is now seeking to bypass Mich Con. He said that the loss of major loads could increase the cost of capital as the investment community reacts to the company's competitive losses.

Mr. Bearman testified that the terms of the special contract are identical to contracts used for existing Rate T-1 and Rate T-2 customers with two exceptions: (1) The rates for the two larger facilities are below the Rate T-2 floor. (2) All four facilities are exempted from new surcharges. He said that it was necessary to deviate from the Rate T-2 floor to retain the James River business. He described the exemption from further surcharges as the result of give and take in the negotiations.

Mr. Bearman said that in considering whether to approve the **special contract**, the Commission should ask whether the utility and its other customers are better off with the **special contract** than they would be if James River bypassed the company's system. He said that if James River bypassed its system, Consumers' revenues would be reduced by almost $925,000 annually and all of James River's contribution to the company's fixed costs would be lost. He said that as long as the **special contract** rates cover the **variable costs** of providing transportation service to James River and makes some contribution to the company's fixed costs, the utility and its other customers are clearly better off with the special contact than without it and the contact should be approved.

Mr. Bearman stated that the sum of the variable costs of providing gas transportation to James River is $425,800 annually in years one through three, ($3,800 for gas distribution, $50,000 for compressor maintenance, and $372,000 for GCR cost of gas effects), for a total of approximately $0.106 per Mcf. Mr. Bearman explained that, with minimum annual revenues of $600,000 in years one through three, the company would collect $174,200 annually in excess of the variable costs of serving James River during years one through three and, with minimum annual revenues of $360,000 in years four and five, Consumers would collect $120,200 annually in excess of the variable costs in the last two years. If consumption remains at 4 Bcf in the last two years, he said that revenues would exceed variable costs by $294,200 annually. He also said that James River has agreed to reduce its annual contract quantity from approximately 6.2 Bcf to 4 Bcf and to cancel its interruptible storage agreement. As a result, approximately 887,000 Mcf of storage capacity are freed up for use by other customers. He calculated the value to other customers of the freed-up storage to be $970,000 annually. [FN3]

Mr. Bearman testified that the company does not foresee unusually high growth in the Kalamazoo area and that the company is in a position to provide service to new customers and to provide additional service to existing customers at existing cost-of-service rates, with or without service to James River. He asserted that all of the costs that can be avoided if James River leaves the company system, both short-term and long-term, have been accounted for in the company's study of the variable costs of serving James River.

Finally, Mr. Bearman testified that a fully allocated cost-of-service approach is not relevant in this case because James River has other alternatives for gas service that allow it to demand a market-based rate. He said that when the Commission created the gas transportation program and authorized a Rate T-2 range of rates 50% above and below the Rate T-1 cost-of-service rate, the Commission did not articulate a reason for that range as opposed to some wider range. He suggested that the resulting range is not well suited to customers who have the ability to bypass the company's system, although the range has worked well for customers with coal displacement and oil displacement capabilities. Mr. Bearman also testified that before the company grants a discount to a customer, it analyzes as much data as it can obtain to evaluate the competitiveness of the customer's alternative, with the result that only 7% of the company's transportation customers receive service at discounted prices. He noted that James River is the only customer to whom Consumers has offered a special contract since the transportation program began in 1989. He also noted that, between rate cases, the company bears the effect of the rates negotiated with Rate T-2 customers and therefore has every incentive to maximize the revenues collected.

In its supplemental brief, Consumers stresses that the cost of the bypass alternative determined the price the company had to offer to retain James River as a customer. Consumers computes that, through 1999, the bypass would cost James River $61,653,823 in total gas costs, the special contract would cost $62,747,122, and the Rate T-2 floor would cost $64,177,670.

In his reply brief, the Attorney General says that Consumers' allegation that it verified the costs and benefits of the bypass alternative is unsupported by the record. He says that Consumers had only an estimate, without the underlying figures and assumptions. As a result, he says, the Commission cannot be confident that the economics of the bypass, which were the basis for the discounted rates, are reasonably accurate. Indeed, he says, Exhibit I-18 suggests that Consumers believed that the cost of the bypass pipeline would be twice what James River claimed. The Attorney General concludes by asking why a price sensitive customer, such as James River, would pursue a special contract that will cost it $1 million more than the bypass alternative. He suggests that the answer is because the bypass option is not prudent or because something undisclosed is going on in this case.

In its initial brief, James River says that at least as far as it is concerned, competition exists and it can obtain a lower delivered cost of gas through the bypass alternative. It says that the testimony and exhibits clearly demonstrate that it is ready, willing, and able to obtain gas transportation service from another supplier. James River says that its statement that it will bypass Consumers' system if the contract is not approved is an economic reality, not a bluff or a threat, because it has a fiduciary duty to its shareholders and an obligation to its employees and customers to reduce the cost of doing business whenever it can prudently do so. It says that there is no apparent basis for objecting to the contract and that, without approval of the contract, James River will be irretrievably lost as a customer for Consumers. James River says that although the rates in the **special contract** are not completely compensatory in terms of a fully allocated cost-of-service study, they do cover all of Consumers' **variable costs** and make a contribution of $140,000 annually towards fixed costs. It further notes that approval would not affect the rates charged to other customers and that the ratemaking effects would be considered in Consumers' next general gas rate case.

The Staff argues that, as a matter of policy, sales customers should not subsidize transportation customers. It says that the transportation program that the Commission approved put Consumers at risk for collecting, on average, the fully allocated cost of service from Rate T-2 customers and it says that the risk should remain on Consumers. The Staff says that it is an important distinction whether the Commission approves a discounted rate or Consumers exercises its discretion to offer a discount for which it is at risk. It says that if the Commission approves the special contract, James River will not be in the Rate T-2 class, which the Staff fears will permit Consumers to seek recovery of the discount from customers not in the Rate T-2 class.

The Staff also argues that the lack of a significant contribution to fixed costs does not warrant such a departure from the Rate T-2 floor. The Staff denies that a contribution of $174,200 is significant or material in the ratemaking process, especially when the contract is not a permanent solution to the bypass threat. The Staff also finds the company's analysis of the variable costs of serving James River to be deficient and unreliable, having been developed as an after-the-fact rationalization for the contract, despite the two years of negotiation that preceded the contract. It points out that Consumers assigned no administrative cost to James River, despite Consumers' officers and employees having devoted substantial time to that customer in the last two years. The Staff suggests that the variable costs may exceed the revenues. The Staff also points to the contradiction in Consumers' position that approval of the contract will deter aggressive interstate pipeline activity and its claim that the James River situation is unique, and says that Consumers did not show that interstate pipelines are aggressively pursuing its customers. It also says that the contract will weaken Consumers' bargaining position with other customers who will demand deep discounts in their transportation rates, resulting in losses that will exceed James River's purported contribution to fixed costs.

The Staff argues that Consumers did not offer the cost-of-service study from its recently filed gas rate case to address concerns about the cost of serving James River, and Consumers objected to the Staffs efforts to have the study admitted into evidence. Further, it argues that Consumers did not offer a single witness with substantial responsibility for negotiating the contract, and Consumers objected to questions to Mr. Joos about the contract provisions and the rationale behind the final offer. It also points out that Mr. Miller and Mr. Biek analyzed the costs of serving James River only after the Commission refused to grant ex parte approval. The Staff thus concludes that its policy objections to the contract remain uncountered and that there continues to be a lack of material benefit to other customers.

Consumers responds that Mr. Bearman testified that the company has an ongoing analysis of transportation customers' competitive alternatives and the economic desirability of offering discounts. He also testified that the negotiators were aware that a $0.15 per Mcf rate would cover the **variable costs**, which aside from the GCR cost of gas effects, were quite minor. It also responds that approval of the **special contract** will not bind the Commission in future cases, but will signal that the Commission will approve a contract in a timely manner when appropriate, which it says will strengthen its bargaining position.

In his supplemental brief, the Attorney General argues that the Commission must evaluate the special contract keeping in mind that Consumers has been less than candid in (1) delaying disclosure of the six-month deadline for Commission action and the existence of a June 30, 1994 letter agreement under which Consumers agreed to assist in construction of the bypass pipeline and to offer reduced transportation rates to James River if the Commission did not approve the contract, (2) representing that the special contract was the entire agreement, when it was not because there was a letter agreement, (3) negotiating a letter agreement with illegal terms, and (4) failing to present a complete present value cost/benefit analysis of the bypass option compared to the special contract. He also says that the Commission must keep in mind that James River failed to present any evidence in support of the economics of the bypass option. He points out that Consumers says that it requires customers to establish the need for a discounted rate, yet Consumers carried the burden in this case. In his reply brief, he adds that Consumers' allegations concerning James River's motives, intent, and proposed actions lack an evidentiary basis because no one from James River testified on those issues. He also adds that the focus of this proceeding should be solely the interests of captive customers rather than the interests of Consumers and its captive customers. He suggests that Consumers is motivated by its desire to obtain approval of the contract so that it will not have to face the financial consequences of the June 30, 1994 letter agreement. He says that, in light of these factors, Consumers' presentation lacks credibility.

James River responds that it is not seeking anything from the Commission and has no obligation to prove anything to the Commission. It says that the economics of the bypass option and the wisdom of James River's business decisions are not properly before the Commission. It says that its choice to pursue the bypass option, if the Commission does not approve the special contract, must be accepted as a given.

The Attorney General continues by arguing that instead of presenting a comprehensive cost/benefit analysis, Consumers presented a 'guess' as to whether the revenues will exceed the **variable costs** of the service. As a result, he says, there is no reasonable assurance that the revenues will actually exceed all **variable**

costs. He finds it incredible that the total labor associated with transporting 4 Bcf of gas and administering the contract could be only 21 hours per year, especially considering the extensive day-to-day dealings that Consumers claimed to have with James River. He also questions the company's position that only 246 feet of high-pressure lines are required to serve James River. He points to Exhibits I-23, I-24, and I-25 as suggesting that there are low-pressure lines involved in providing service to James River, with a **variable cost** not included in Consumers' calculation. Finally, he says that Consumers has not quantified the positive effect on its business risk when a customer like James River, which brings significant business risk to the utility, leaves the system. He suggests that even if the positive effect on the cost of common equity is very small, the effect on rates is likely to be more than the company's optimistic guess as to James River's contribution to fixed costs. He concludes that, when all costs are considered, it is cheaper for other customers if the Commission does not approve the **special contract**.

Consumers responds that the Attorney General has not indicated what more the cost/benefit analysis should include beyond the items the company has included. Furthermore, it says that there is no record evidence that the loss of James River as a customer would permit the company to reduce its administrative and general costs. The company also responds that the two larger facilities, the only two for which it looked at the variable costs, use only high pressure lines. Finally, it responds that increased competition leads to more, not less, business risk.

In his reply brief, Attorney General says that Consumers has calculated, in its recent gas rate case, that the cost of service for gas transportation is $0.64 per Mcf. He suggests that it is highly unlikely that a $0.15 per Mcf rate will cover all variable costs and make some contribution to fixed costs.

Based on the record and arguments of the parties, the Commission concludes that the contract should be approved. There is an adequate evidentiary basis to conclude that James River has an economic bypass alternative and that the **special contract** rates are necessary to induce it to remain as a customer on Consumers' system. There is also an adequate evidentiary basis to conclude that the rates in the **special contract** will cover the **variable costs** of serving James River and will provide a contribution to system fixed costs. Consumers' management considered these factors and decided to enter into the **special contract** as the best deal that could be obtained for the utility. The Commission therefore approves the resulting contract.

Ratemaking Treatment

[5, 6] Consumers says that it is not asking the Commission to rule at this time on the recovery from other customers of either the discount from the Rate T-2 floor or the waiver of future surcharges, issues that it says should be decided in future cases.

Staff witness Collins said that the Commission should recognize that approval of the contract at this time gives Consumers the advantage in future cases and will make it difficult for other parties to argue that shareholders should bear the discounts.

The Attorney General says that the Commission must consider at this time who will be asked to bear the cost of these discounts in the future. He says that approval of the contract without consideration of that issue would mean that the contract would be approved without consideration given to the true economic consequences to ratepayers.

Consistent with its view that Consumers' management should be permitted to enter into this special contract, the Commission also believes, as a general matter, that the utility should assume full responsibility for negotiating the discounted prices and that its shareholders should expect to absorb much, if not all, of any revenue shortfall caused by the pricing and other contract terms that the utility negotiates. In this case, the Commission has determined that approval of the contract depends on the revenue shortfall created by the difference between the contract price and the Rate T-2 floor being the responsibility of Consumers' shareholders and prohibiting the company from seeking to recover that amount from other customers. The treatment of the potential revenue shortfall created by the difference between the Rate T-2 floor and the transportation class cost of service will be addressed and resolved in the pending general rate case, where that revenue shortfall is already at issue.

Other Staff Concerns

[7] The testimony of the Staff witness and the Staff's initial brief state the Staff concerns with a somewhat different emphasis, which merits discussion.

The Staff says that approval of the special contract would commit Consumers to providing service to James River under a long-term, full service contract, at rates just above the short-run marginal cost of service, as calculated by Consumers, and possibly below the short-run marginal cost. The Staff says that, as a result, Consumers would never have the opportunity to recover its fully allocated costs of providing service to James River, even though, in the long- run, a utility must be allowed to recover its long-run costs in order to remain viable and to have the opportunity to earn a fair rate of return. Therefore, the Staff says that establishing rates for a long-term, full service contract based on the short-run marginal cost of providing service is bad policy. The Staff says that, at the very minimum, the Commission should consider the long- run costs of providing service to the specific customer as the basis for the rate and then allow only some discounting, at the utility's discretion, to meet short-term market challenges in order to maximize revenues. The Staff also says that short-run marginal cost should be the floor for that type of discounting. The Staff concludes, however, that setting rates for long-run contracts below the long-run cost institutionalizes the full discount, prevents the utility from taking actions to avoid costs that are variable in the long-run, and eventually requires that the discount be recovered from other customers or from shareholders.

The Staff says that the contract is a full-service contract that provides for all services available to any other Rate T-1 or Rate T-2 customer. The Staff says that there is nothing in the contract that would allow Consumers to offer the capacity used by James River to another customer, even if that customer were willing to pay the fully allocated cost of service. Therefore, the Staff says, that to add a new customer or to offer more service to other existing customers, Consumers would have to incur additional costs. The Staff acknowledges that Consumers had stated that it is not required to make any additional investment to serve this load, but he said that it must stand ready to do so if any additional investment is needed.

The Staff also says that there is a significant possibility that the contract rate may be below the short-run marginal cost. The Staff notes that, under Consumers' calculation, the difference between revenues and expenses is just $0.0372 per Mcf. The Staff states that this calculation includes some, but not necessarily all, of the short-run costs associated with James River. The Staff says that because of the schedule and limited information provided by Consumers, it was not possible for the Staff to conduct a study to determine the short-run variable costs associated with serving James River.

With respect to long-term costs, the Staff says that if the long-run cost of serving James River is the same as the embedded cost of serving the average transportation customer, then the cost of serving James River will ultimately exceed revenues by $1.2 million per year. The Staff says that because neither the Staff nor Consumers had conducted a study to determine the long-run marginal cost of serving James River, the exact amount of the revenue shortfall was not known. The Staff believes that many of the costs included in the fully allocated cost-of-service study would eventually have to be incurred to serve James River in the long run. The

Staff says that to offset this potentially large revenue shortfall, Consumers proposed to collect a spread of only $140,450 [FN4] per year, assuming that Consumers' calculation of the **variable cost** is accepted. The Staff says that accepting such a large risk with such a meager potential return is unreasonable and imprudent, especially when James River's threat to bypass constitutes a permanent market challenge, unlike the threat from other fuels whose competitive position is subject to change. The Staff says that the Staff does not agree with Consumers' position that as long as the discounted rate covers the **variable cost** of providing service and makes some contribution to fixed cost recovery, the utility and its other customers are clearly better off with the **special contract**.

In its initial brief, the Staff adds that the decision on the contract should be based primarily on the economic effect on the local distribution company and its other customers, but it denies that the utility and its other customers would be better off in the long run if the Commission approves the special contract. Furthermore, it contends that approval of the special contract would set a bad ratemaking precedent and would violate sound policies established in Consumers' last general rate case. It says that approval of the company's request would have the Commission deviate from its clearly stated policy of requiring that all on-system transportation be performed pursuant to Rate T-1 or Rate T-2. It acknowledges that the Commission heard argument regarding the need for a flexible transportation rate that would allow Consumers to meet competitive challenges that were emerging. It notes that bypass was frequently mentioned as one of the alternatives available to system transportation customers. It says that the Commission addressed the need to meet the emerging competitive challenges by offering flexible pricing under Rate T-2. It further argues that the Commission reinforced its sound policy of requiring on-system transportation to be performed under Rate T-1 or Rate T-2 with another sound policy of linking the range of rates to the cost of service. It says that the perceived cost of James River's bypass alternative should be used only to determine what price within the Rate T-2 range should be offered to James River.

In its initial brief, Consumers argues that it is irrelevant to argue that the rate for James River is discounted, but the service is not reduced, because the service provided to all Rate T-1 and Rate T-2 customers is the same. Only the price is different. It says that Rate T-2 is negotiable, to recognize that certain customers can demand a lower rate or they will leave the system, us James River can. It says that the value of the service to James River is lower and justifies the special contract rate. It also points out that, under Rate T- 2, it can already discount rates for long-term contracts below the fully allocated cost of service, which it says is necessary in certain competitive situations to prevent the loss of load, and those discounts may be permanent. It says that under both the special contract and Rate T-2, it may be unable to collect its fully allocated costs. It also adds that it can offer rates based on a fully-allocated cost of service to new customers, regardless of whether it continues to serve James River. It also says that Mr. Collin's testimony contradicts his testimony in the company's last gas rate case, Cases Nos. U- 8924 et al., where he proposed a $0.10 floor and recognized that fully allocated costs were not appropriate when the company does not have a monopoly position. In those situations, the company says, he admitted that the market would determine the price.

James River says that it makes no sense at this time to insist that all on- system transportation be performed under Rate T-1 or Rate T-2, especially because if the Commission does not approve the contract, there are no winners. It says that because it has the bypass option, a policy of linking rates to the cost-of-service is irrelevant. It suggests that the **special contract** rate should be analyzed in terms of the coverage of **variable costs** and the contribution to fixed costs, rather than on the basis of a fully allocated cost-of-service study. It says that recovery of fully allocated costs is not an alternative because it can and will bypass the system.

The Commission is not committed to a policy that transportation may occur only on Rate T-1 or Rate T-2, rather than pursuant to special contracts, particularly when the discount offered by Consumers to James River differs only in size, not character, from the discount already offered to Rate T-2 customers. For customers in unique circumstances, it may be necessary to be more flexible than Rate T-2 permits and, in the long-run, Consumers may find it necessary to offer further discounted prices to retain those customers on the system. At least initially, it is for Consumers' management to decide whether to pursue that course of action and to accept the risk that the contribution to fixed costs is inconsequential, although the Commission retains the authority to decide the ratemaking effects of the company's chosen course. In this case, the Commission cannot conclude that approval of the special contract will have any measurable effect on Consumers' financial viability, even if its shareholders are ultimately required to bear the entire discount that Consumers' management granted to James River. Finally, it does not appear that Consumers will be required to expend any large sums to serve new customers in the Kalamazoo area, even if James River remains a customer.

Discrimination

[8-11] The Attorney General says that, under relevant law, Consumers must offer this same rate to other similarly situated customers and, thus, Commission approval of a contract with a rate below the cost of service is not in other customers' best interest.

Consumers responds that the rates under the contract are not discriminatory because James River's competitive bypass alternative creates a reasonable distinction between James River and other transportation customers.

The possibility of discrimination in future dealings with requests for special contracts is not a reason to reject the special contract. The Commission must presume that Consumers negotiated the contract with a knowledge that it could not lawfully discriminate against other similarly situated customers. The Commission expects Consumers to act in accordance with applicable law. Customers remain free to pursue their remedies for unlawful discrimination.

Surcharges

[12] The Attorney General challenges the legality of the contract provision that exempts James River from future surcharges during the five-year term of the contract. He says that the Commission will be free in the future to set reasonable rates based on then-current facts and circumstances and that this contract provision cannot prevent the Commission from doing so in the future.

The Commission does not find that approving an exemption from future surcharges is different in any relevant manner than approving a rate below the Rate T-2 floor. Under both, the customer pays the rates required by the contract. In any event, the effect in this case, when new, large surcharges are not expected, appears to be minimal. Issues about discrimination against other customers can be addressed when and if they arise.

New Construction

[13] Staff witness Collins indicated a concern that proposed construction in the Kalamazoo area may not be specifically needed to serve James River, but may also not be needed if James River were to leave the system.

Mr. Miller and Mr. Biek explained that the James River load does not affect the company's planned construction and capital expenditures. Mr. Miller testified that the company does not project any need for system improvements for the portion of the company's gas distribution system that is used to serve James River for the next five years. Mr. Biek explained that the company's planned Kalamazoo area construction expenditures are unrelated to the James River load. Mr. Biek explained that the company does intend to install a new feed off its gas transmission system on the east side of Kalamazoo, but the James River load is served from the west side. Mr. Biek concluded that the proposed expansion of the transmission system will be required regardless of whether the James River load leaves the system. He also suggested that if the James River load is lost, the cost of the proposed construction in the Kalamazoo area may increase if the connection with Panhandle on the east side is used to meet James River's bypass load.

The record does not provide a basis to disagree with Consumers' assertion that retaining James River as a customer will not affect the company's planned construction during the term of the contract.

June 30, 1994 Letter Agreement

The Attorney General says that Consumers' conduct surrounding the letter agreement amounts to material misrepresentation that cannot be tolerated, especially when Consumers did not provide that agreement until the morning of February 1, 1995. He says that the agreement contains a number of incredible provisions and one unlawful provision: Consumers agreed to a six-month deadline for Commission action, Consumers agreed to build or arrange to have built the bypass pipeline if the six-month deadline passed, and Consumers agreed to provide gas transportation at rates below Commission-approved rates while the pipeline was under construction. He says that when Consumers filed the special contract, it falsely represented that the special contract contained the entire agreement of the parties. As a result, he says, the Commission cannot confidently say that Consumers has been candid in other areas of this proceeding.

As to the provision of the letter agreement by which Consumers agreed to effectively charge James River less than Commission-approved rates while the pipeline was under construction, the Attorney General says that it is unlawful and absolutely void. He therefore requests that the Commission order Consumers not to provide any service under the June 30, 1994 letter agreement.

Consumers says that the terms of the letter agreement are irrelevant to the issue of whether the special contract should be approved. It says that if any of the provisions of the letter agreement become operative and require Commission approval, the company will request the appropriate approval.

James River says that the Commission cannot order Consumers to abrogate its contractual commitments. It suggests that the parties to the contract can resolve any questions about the contract without legal guidance from the Attorney General.

The Staff requests that the Commission order Consumers to report its intentions with regard to the commitments in the letter agreement so that the Commission can decide if further proceedings are warranted.

The Commission concludes that the letter agreement is technically irrelevant to the issue of whether the special contract should be approved, but the existence of such an agreement and the manner in which it finally came to light do nothing to assist the Commission in deciding whether to approve the special contract. Similarly, the agreement and Consumers' conduct do nothing to enhance Consumers' credibility. Nevertheless, the Commission expects that the approval granted by this order will render the terms of the letter agreement irrelevant to Consumers' future dealings with James River. Still, it may bear repeating: Consumers may not charge or collect for a regulated service a rate or charge that varies in any manner from the rates and charges approved by the Commission. Further, Consumers shall keep the Staff informed of the status of its commitments in the letter agreement.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, R 460.17101 et seq.

b. With the ratemaking treatment discussed in this order, the special contract between Consumers and James River is reasonable and in the public interest, and should be approved.

THEREFORE, IT IS ORDERED that the special gas transportation contract between Consumers Power Company and James River Corporation is approved.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26.

By its action of February 23, 1995. FOOTNOTES

FN1 Consumers filed an application for leave to appeal the schedule set by the ALJ, which it later withdrew.

FN2 On December 21, 1994, James River filed a written agreement to these procedures.

FN3 The Attorney General points out that this alleged benefit does not accrue as a result of the special contract because it would also accrue if James River left the system. The Staff agrees and adds that Consumers is obligated to take reasonable and prudent actions to reduce the cost of gas to its sales customers, including not entering into unreasonable storage agreements with transportation customers.

FN4 Consumers later revised this amount to $174,200.

END OF DOCUMENT

Re Consumers Power Company
Case No. U-10651

Michigan Public Service Commission
February 23, 1995

ORDER authorizing a natural gas local distribution company (LDC) to enter a special contract for the provision of gas transportation service to an industrial customer at discount rates.

Commission finds that there is an adequate evidentiary basis to conclude that the industrial customer has an economic bypass alternative and that the special contract rates are necessary to induce the customer to remain on the LDC system. Moreover, it finds that there is an adequate evidentiary basis to conclude that the rates in the special contract will cover the variable costs of serving the industrial customer and will provide a contribution to the fixed costs of the LDC system.

Any revenue shortfall created by the difference between the special contract rate and the otherwise applicable tariffed rate floor is the responsibility of shareholders -- i.e., the LDC is prohibited from seeking to recover that shortfall from other customers. However, the potential revenue shortfall created by the difference between the tariff rate floor and the transportation class cost of service will be addressed and resolved in a pending general rate case.

Commission states that it presumes that the LDC negotiated the special contract with a knowledge that it may not discriminate against other similarly situated customers and that it expects the LDC to act in accordance with applicable law. Customers of the LDC are, the commission notes, free to pursue remedies in the event of unlawful discrimination.

Commission rejects a challenge to the legality of a contract provision that exempts the industrial customer from future surcharges that may occur during the five-year term of the contract, again noting that issues concerning discrimination against other customers can be addressed when and if they arise.

Commission finds no basis to disagree with the LDC's assertion that retaining the industrial customer will not affect planned construction during the term of the contract.

For prior order that had required the utility to present additional evidence addressing the cost of serving the special contract customer, the economic feasibility of the customer's bypass option, and the implications of negotiated arrangements for other customers, see Re Consumers Power Co., 159 PUR4th 162 (Mich.P.S.C.1995).

P.U.R. Headnote and Classification

1.

RATES

s166

Mi.P.S.C. 1995

[MICH.] Reasonableness -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Special contract -- Gas transportation service -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

2.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Special factors -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Gas transportation service -- Special contract -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

3.

RATES

s140

Mi.P.S.C. 1995

[MICH.] Reasonableness -- Competition -- Load retention -- Negotiated rates -- Anti-bypass discounts -- Special contract -- Gas transportation service -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

4.

MONOPOLY AND COMPETITION

s58

Mi.P.S.C. 1995

[MICH.] Natural gas -- Anti-bypass discounts -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

5.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Revenue shortfalls -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

6.

REVENUE

s5

Mi.P.S.C. 1995

[MICH.] Natural gas -- Discount transportation service -- Treatment of revenue shortfall -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

7.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Pricing -- Recovery of variable costs -- Contribution to fixed system costs -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

8.

DISCRIMINATION

s26

Mi.P.S.C. 1995

[MICH.] Special contract rates -- Anti-bypass discount -- Legality -- Natural gas local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

9.

DISCRIMINATION

s61

Mi.P.S.C. 1995

[MICH.] Concessions to particular customer -- Large industrial customer -- Special contract rate -- Anti-bypass discount -- Legality -- Natural gas local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

10.

DISCRIMINATION

s109

Mi.P.S.C. 1995

[MICH.] Natural gas rates -- Special contract rate -- Anti- bypass discount -- Legality -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

11.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Legality -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

12.

RATES

s380

Mi.P.S.C. 1995

[MICH.] Natural gas rate design -- Transportation service -- Special contract rate -- Anti-bypass discount -- Pricing -- Exemption from surcharges -- Local distribution company.

Re Consumers Power Company

P.U.R. Headnote and Classification

13.

GAS

s7

Mi.P.S.C. 1995

[MICH.] Natural gas -- Load management -- Special contract rate -- Anti- bypass discount -- Effect on planned construction -- Local distribution company.

Re Consumers Power Company

Before Strand, chairman, and Russell and O'Donnell, commissioners.

BY THE COMMISSION:

OPINION AND ORDER

I.

HISTORY OF PROCEEDINGS

On June 30, 1994, Consumers Power Company (Consumers) and James River Corporation agreed to enter into a special contract for the provision of natural gas transportation service. The rates under the special contract are less than those authorized in Consumers' currently effective transportation tariffs, Rate T-1 and Rate T-2. Consumers says that it found it necessary to offer James River this special contract in order to prevent James River from bypassing the company's system in favor of directly connecting with Panhandle Eastern Pipe Line Company's (Panhandle) pipeline located near James River's Kalamazoo area facilities.

On August 5, 1994, Consumers filed an application for ex parte approval of the special contract, with the pricing terms deleted from the attached copy of the contract. On September 20, 1994, after giving up its efforts to protect the confidentiality of the contract pricing terms, Consumers filed a complete copy of the special contract.

On October 27, 1994, Consumers filed the testimony and exhibits of four witnesses in support of the application. A prehearing conference was held on the same day before Administrative Law Judge James N. Rigas (ALJ). He granted the petitions to intervene filed by James River and Attorney General Frank J. Kelley (Attorney General). Consumers requested an expedited hearing that would have permitted a final Commission order on or before February 3, 1995, because James River had indicated that it would pursue a bypass alternative if the contract were not approved by then. The ALJ set an abbreviated schedule, although not as expedited as Consumers. requested. [FN1]

The Commission Staff (Staff) filed the testimony of one witness on November 23, 1994.

Cross-examination was scheduled to commence on December 14, 1994. On that date, the parties (except James River, which was not present) agreed to an accelerated schedule that included (1) binding in the prefiled testimony with the exception of a portion of the Staff witness's testimony, (2) a waiver of the right to cross-examine the witnesses and a waiver of the right to file rebuttal testimony, (3) the filing of simultaneous briefs and a waiver of the right to file reply briefs, and (4) the submission of the case directly to the Commission with a waiver of Section 81 of the Administrative Procedures Act, dispensing with the need for a proposal for decision. [FN2] The record at that point consisted of 96 pages of transcript and 13 exhibits.

On January 6, 1995, Consumers, the Attorney General, the Staff, and James River filed initial briefs.

On January 17, 1995, the Commission issued an order remanding the case to the ALJ for further development of the record. In response to the Commission's order, Consumers filed supplemental testimony of three witnesses.

The cross-examination of all witnesses occurred on February 1 and 2, 1995. In addition, the rebuttal testimony of David W. Joos, Executive Vice President and Chief Operating Officer of Consumers' Electric Division; Robert Russel, James River's Group Service Manager; and Michael L. Collins, a Gas Cost Recovery Specialist in the Commission's Gas Division, was presented and cross-examined on February 2, 1995.

On February 10, 1995, Consumers, the Attorney General, and the Staff filed supplemental briefs. On February 17, 1995, Consumers, the Attorney General, the Staff, and James River filed reply briefs. Because the Commission read the record or attended the hearings or both, the ALJ did not prepare a proposal for decision. The complete record consists of 496 pages of transcript and 26 exhibits.

Consumers and James River urge the Commission to approve the special contract. The Staff and the Attorney General urge the Commission to reject the special contract.

II.

DISCUSSION

Contract Approval

[1-4] The contract provides a rate of $0.15 per thousand cubic feet (Mcf) for years one through three and a rate of $0.18 per Mcf for years four and five for the two larger James River facilities in the Kalamazoo area. These rates are below the Rate T-2 floor of $0.2367 per Mcf. The company's two smaller facilities would

continue to pay the Rate T-1 rate, which is now $0.4734. Current surcharges would apply, but future surcharges would not apply to any of the facilities. James River's annual minimum consumption would be 4 billion cubic feet (Bcf) for years one through three and 2 Bcf for years four and five. Its load balancing would be 8.5% of the minimum volume, and its storage contract would be canceled. The maximum daily quantity would be reduced by almost half.

Consumers offered the testimony of four witnesses in support of its application.

David E. Madden, a Senior Engineer in Consumers' Marketing Department, testified that James River's larger Kalamazoo area facilities are the first and sixth largest users of natural gas on Consumers' system, using more than 4 Bcf per year.

Mr. Madden testified that in September 1992, James River requested that Consumers remove a no-bypass clause from its gas transportation contract. James River wanted to pursue a bypass alternative because the storage available to it had been decreased and it was dissatisfied with the surcharges imposed on Rate T-2 customers. Negotiations began and the contract was modified in January 1993. In August 1993, James River notified Consumers of its intent to bypass the utility's system. Mr. Madden noted that James River's facilities are located in a manner that would permit James River to build four miles of pipeline along a railroad right-of-way to Panhandle's city gate, which Consumers believed made the bypass economical. Negotiations continued, with James River rejecting two offers made in October 1993.

Mr. Madden testified that James River provided a spreadsheet to Consumers, Exhibit A-5, that showed a savings of $3.8 million from the last quarter of 1994 through 1999 if it bypassed Consumers' system, based on Consumers' October 13, 1993 offer. Based on that exhibit, he testified that Consumers would have had to offer a rate of negative $0.043 per Mcf in 1994 and a rate of $0.135 per Mcf in 1997 to match the economics of the bypass option. On June 28, 1994, Consumers offered James River a five-year special contract with rates below the Rate T-2 floor. James River rejected that offer. On June 30, 1994, Consumers countered with a change to the annual load balancing, and James River accepted.

In his supplemental testimony, Mr. Madden provided additional explanation for some of the figures on the James River spreadsheet and made a correction. He also sponsored Exhibit A-15, which compares James River's gas costs under the bypass alternative, the special contract, and the Rate T-2 floor. He calculated that James River would realize savings of more than $2.5 million if it were to pursue the bypass alternative instead of choosing to stay on Rate T-2 at the floor price. He acknowledged that the special contract requires James River to pay in excess of $1 million more than it would pay for the bypass option, but he believed that James River is willing to pay that price because of the value it places on the company's transportation service. He also testified that he now expects James River's load to remain near 4 Bcf for the full term of the contract, despite James River's right to reduce its annual contract quantity in the last two years. The effect, he said, is to increase the benefits of the special contract for other customers.

Finally, Mr. Madden noted that James River has a facility in Camas, Washington, that bypassed the local utility. He stated that James River would definitely bypass Consumers' system if the Commission did not approve the special contract. He testified that the special contract represents the best bargain that Consumers could obtain and still keep James River as a customer.

Patrick D. Miller, Consumers' Manager of Gas Distribution Services, described the variable distribution costs associated with providing gas transportation service to James River. He explained that the costs include meter installation and maintenance, the odorant added to the gas, and costs associated with leak surveys, leak repairs, staking, operating mains and services, and maintaining adequate cathodic protection. He estimated the total annual variable distribution costs for the two larger James

River facilities to be approximately $3,800 per year.

John R. Biek, Consumers' Director of Gas Supply, Planning, and Control, described the effect on the company's gas transmission and storage system from continuing to serve James River. He explained that the only variable transmission and storage costs are compressor station maintenance and the effect on the cost of gas for gas cost recovery (GCR) customers. He estimated the compressor maintenance expense to be approximately $50,000 per year. The GCR effect is due to the authorized tolerance level of 8.5% associated with the special contract. With an annual contract quantity of 4 Bcf, James River is entitled to 340,000 Mcf of authorized tolerance level, which is storage capacity that could potentially be used to benefit GCR customers if James River left the system. The potential effect on the cost of gas for GCR customers is approximately $372,000 annually in the first three years and $236,000 annually in the last two years. That cost represents the estimated higher cost of buying winter gas using firm transportation to deliver the gas directly to GCR customers as opposed to purchasing gas on interruptible transportation and placing it in storage during the summer injection cycle.

James F. Bearman, Rates Director in Consumers' Gas Division, testified that the James River situation represents the first viable bypass threat since the utility's current gas transportation program began in 1989. He argued that a bypass by James River would send a negative competitive signal to other major customers on the system, would result in spreading the fixed costs of the lost load to remaining customers, and might spur further aggressive competitive behavior by interstate pipelines. He noted that National Steel in Ecorse bypassed Michigan Consolidated Gas Company (Mich Con) in 1989 and Escanaba Paper Company is now seeking to bypass Mich Con. He said that the loss of major loads could increase the cost of capital as the investment community reacts to the company's competitive losses.

Mr. Bearman testified that the terms of the special contract are identical to contracts used for existing Rate T-1 and Rate T-2 customers with two exceptions: (1) The rates for the two larger facilities are below the Rate T-2 floor. (2) All four facilities are exempted from new surcharges. He said that it was necessary to deviate from the Rate T-2 floor to retain the James River business. He described the exemption from further surcharges as the result of give and take in the negotiations.

Mr. Bearman said that in considering whether to approve the special contract, the Commission should ask whether the utility and its other customers are better off with the special contract than they would be if James River bypassed the company's system. He said that if James River bypassed its system, Consumers' revenues would be reduced by almost $925,000 annually and all of James River's contribution to the company's fixed costs would be lost. He said that as long as the special contract rates cover the variable costs of providing transportation service to James River and makes some contribution to the company's fixed costs, the utility and its other customers are clearly better off with the special contact than without it and the contact should be approved.

Mr. Bearman stated that the sum of the variable costs of providing gas transportation to James River is $425,800 annually in years one through three, ($3,800 for gas distribution, $50,000 for compressor maintenance, and $372,000 for GCR cost of gas effects), for a total of approximately $0.106 per Mcf. Mr. Bearman explained that, with minimum annual revenues of $600,000 in years one through three, the company would collect $174,200 annually in excess of the variable costs of serving James River during years one through three and, with minimum annual revenues of $360,000 in years four and five, Consumers would collect $120,200 annually in excess of the variable costs in the last two years. If consumption remains at 4 Bcf in the last two years, he said that revenues would exceed variable costs by $294,200 annually. He also said that James River has agreed to reduce its annual contract quantity from approximately 6.2 Bcf to 4 Bcf and to cancel its interruptible storage agreement. As a result, approximately 887,000 Mcf of storage capacity are freed up for use by other customers. He calculated the value to other customers of the freed-up storage to be $970,000 annually. [FN3]

Mr. Bearman testified that the company does not foresee unusually high growth in the Kalamazoo area and that the company is in a position to provide service to new customers and to provide additional service to existing customers at existing cost-of-service rates, with or without service to James River. He asserted that all of the costs that can be avoided if James River leaves the company system, both short-term and long-term, have been accounted for in the company's study of the variable costs of serving James River.

Finally, Mr. Bearman testified that a fully allocated cost-of-service approach is not relevant in this case because James River has other alternatives for gas service that allow it to demand a market-based rate. He said that when the Commission created the gas transportation program and authorized a Rate T-2 range of rates 50% above and below the Rate T-1 cost-of-service rate, the Commission did not articulate a reason for that range as opposed to some wider range. He suggested that the resulting range is not well suited to customers who have the ability to bypass the company's system, although the range has worked well for customers with coal displacement and oil displacement capabilities. Mr. Bearman also testified that before the company grants a discount to a customer, it analyzes as much data as it can obtain to evaluate the competitiveness of the customer's alternative, with the result that only 7% of the company's transportation customers receive service at discounted prices. He noted that James River is the only customer to whom Consumers has offered a special contract since the transportation program began in 1989. He also noted that, between rate cases, the company bears the effect of the rates negotiated with Rate T-2 customers and therefore has every incentive to maximize the revenues collected.

In its supplemental brief, Consumers stresses that the cost of the bypass alternative determined the price the company had to offer to retain James River as a customer. Consumers computes that, through 1999, the bypass would cost James River $61,653,823 in total gas costs, the special contract would cost $62,747,122, and the Rate T-2 floor would cost $64,177,670.

In his reply brief, the Attorney General says that Consumers' allegation that it verified the costs and benefits of the bypass alternative is unsupported by the record. He says that Consumers had only an estimate, without the underlying figures and assumptions. As a result, he says, the Commission cannot be confident that the economics of the bypass, which were the basis for the discounted rates, are reasonably accurate. Indeed, he says, Exhibit I-18 suggests that Consumers believed that the cost of the bypass pipeline would be twice what James River claimed. The Attorney General concludes by asking why a price sensitive customer, such as James River, would pursue a special contract that will cost it $1 million more than the bypass alternative. He suggests that the answer is because the bypass option is not prudent or because something undisclosed is going on in this case.

In its initial brief, James River says that at least as far as it is concerned, competition exists and it can obtain a lower delivered cost of gas through the bypass alternative. It says that the testimony and exhibits clearly demonstrate that it is ready, willing, and able to obtain gas transportation service from another supplier. James River says that its statement that it will bypass Consumers' system if the contract is not approved is an economic reality, not a bluff or a threat, because it has a fiduciary duty to its shareholders and an obligation to its employees and customers to reduce the cost of doing business whenever it can prudently do so. It says that there is no apparent basis for objecting to the contract and that, without approval of the contract, James River will be irretrievably lost as a customer for Consumers. James River says that although the rates in the special contract are not completely compensatory in terms of a fully allocated cost-of-service study, they do cover all of Consumers' variable costs and make a contribution of $140,000 annually towards fixed costs. It further notes that approval would not affect the rates charged to other customers and that the ratemaking effects would be considered in Consumers' next general gas rate case.

The Staff argues that, as a matter of policy, sales customers should not subsidize transportation customers. It says that the transportation program that the Commission approved put Consumers at risk for collecting, on average, the fully allocated cost of service from Rate T-2 customers and it says that the risk should remain on Consumers. The Staff says that it is an important distinction whether the Commission approves a discounted rate or Consumers exercises its discretion to offer a discount for which it is at risk. It says that if the Commission approves the special contract, James River will not be in the Rate T-2 class, which the Staff fears will permit Consumers to seek recovery of the discount from customers not in the Rate T-2 class.

The Staff also argues that the lack of a significant contribution to fixed costs does not warrant such a departure from the Rate T-2 floor. The Staff denies that a contribution of $174,200 is significant or material in the ratemaking process, especially when the contract is not a permanent solution to the bypass threat. The Staff also finds the company's analysis of the variable costs of serving James River to be deficient and unreliable, having been developed as an after-the-fact rationalization for the contract, despite the two years of negotiation that preceded the contract. It points out that Consumers assigned no administrative cost to James River, despite Consumers' officers and employees having devoted substantial time to that customer in the last two years. The Staff suggests that the variable costs may exceed the revenues. The Staff also points to the contradiction in Consumers' position that approval of the contract will deter aggressive interstate pipeline activity and its claim that the James River situation is unique, and says that Consumers did not show that interstate pipelines are aggressively pursuing its customers. It also says that the contract will weaken Consumers' bargaining position with other customers who will demand deep discounts in their transportation rates, resulting in losses that will exceed James River's purported contribution to fixed costs.

The Staff argues that Consumers did not offer the cost-of-service study from its recently filed gas rate case to address concerns about the cost of serving James River, and Consumers objected to the Staffs efforts to have the study admitted into evidence. Further, it argues that Consumers did not offer a single witness with substantial responsibility for negotiating the contract, and Consumers objected to questions to Mr. Joos about the contract provisions and the rationale behind the final offer. It also points out that Mr. Miller and Mr. Biek analyzed the costs of serving James River only after the Commission refused to grant ex parte approval. The Staff thus concludes that its policy objections to the contract remain uncountered and that there continues to be a lack of material benefit to other customers.

Consumers responds that Mr. Bearman testified that the company has an ongoing analysis of transportation customers' competitive alternatives and the economic desirability of offering discounts. He also testified that the negotiators were aware that a $0.15 per Mcf rate would cover the variable costs, which aside from the GCR cost of gas effects, were quite minor. It also responds that approval of the special contract will not bind the Commission in future cases, but will signal that the Commission will approve a contract in a timely manner when appropriate, which it says will strengthen its bargaining position.

In his supplemental brief, the Attorney General argues that the Commission must evaluate the special contract keeping in mind that Consumers has been less than candid in (1) delaying disclosure of the six-month deadline for Commission action and the existence of a June 30, 1994 letter agreement under which Consumers agreed to assist in construction of the bypass pipeline and to offer reduced transportation rates to James River if the Commission did not approve the contract, (2) representing that the special contract was the entire agreement, when it was not because there was a letter agreement, (3) negotiating a letter agreement with illegal terms, and (4) failing to present a complete present value cost/benefit analysis of the bypass option compared to the special contract. He also says that the Commission must keep in mind that James River failed to present any evidence in support of the economics of the bypass option. He points out that Consumers says that it requires customers to establish the need for a discounted rate, yet Consumers carried the burden in this case. In his reply brief, he adds that Consumers' allegations concerning James River's motives, intent, and proposed actions lack an evidentiary basis because no one from James River testified on those issues. He also adds that the focus of this proceeding should be solely the interests of captive customers rather than the interests of Consumers and its captive customers. He suggests that Consumers is motivated by its desire to obtain approval of the contract so that it will not have to face the financial consequences of the June 30, 1994 letter agreement. He says that, in light of these factors, Consumers' presentation lacks credibility.

James River responds that it is not seeking anything from the Commission and has no obligation to prove anything to the Commission. It says that the economics of the bypass option and the wisdom of James River's business decisions are not properly before the Commission. It says that its choice to pursue the bypass option, if the Commission does not approve the special contract, must be accepted as a given.

The Attorney General continues by arguing that instead of presenting a comprehensive cost/benefit analysis, Consumers presented a 'guess' as to whether the revenues will exceed the variable costs of the service. As a result, he says, there is no reasonable assurance that the revenues will actually exceed all variable costs. He finds it incredible that the total labor associated with transporting 4 Bcf of gas and administering the contract could be only 21 hours per year, especially considering the extensive day-to-day dealings that Consumers claimed to have with James River. He also questions the company's position that only 246 feet of high-pressure lines are required to serve James River. He points to Exhibits I-23, I-24, and I-25 as suggesting that there are low-pressure lines involved in providing service to James River, with a variable cost not included in Consumers' calculation. Finally, he says that Consumers has not quantified the positive effect on its business risk when a customer like James River, which brings significant business risk to the utility, leaves the system. He suggests that even if the positive effect on the cost of common equity is very small, the effect on rates is likely to be more than the company's optimistic guess as to James River's contribution to fixed costs. He concludes that, when all costs are considered, it is cheaper for other customers if the Commission does not approve the special contract.

Consumers responds that the Attorney General has not indicated what more the cost/benefit analysis should include beyond the items the company has included. Furthermore, it says that there is no record evidence that the loss of James River as a customer would permit the company to reduce its administrative and general costs. The company also responds that the two larger facilities, the only two for which it looked at the variable costs, use only high pressure lines. Finally, it responds that increased competition leads to more, not less, business risk.

In his reply brief, Attorney General says that Consumers has calculated, in its recent gas rate case, that the cost of service for gas transportation is $0.64 per Mcf. He suggests that it is highly unlikely that a $0.15 per Mcf rate will cover all variable costs and make some contribution to fixed costs.

Based on the record and arguments of the parties, the Commission concludes that the contract should be approved. There is an adequate evidentiary basis to conclude that James River has an economic bypass alternative and that the special contract rates are necessary to induce it to remain as a customer on Consumers' system. There is also an adequate evidentiary basis to conclude that the rates in the special contract will cover the variable costs of serving James River and will provide a contribution to system fixed costs. Consumers' management considered these factors and decided to enter into the special contract as the best deal that could be obtained for the utility. The Commission therefore approves the resulting contract.

Ratemaking Treatment

[5, 6] Consumers says that it is not asking the Commission to rule at this time on the recovery from other customers of either the discount from the Rate T-2 floor or the waiver of future surcharges, issues that it says should be decided in future cases.

Staff witness Collins said that the Commission should recognize that approval of the contract at this time gives Consumers the advantage in future cases and will make it difficult for other parties to argue that shareholders should bear the discounts.

The Attorney General says that the Commission must consider at this time who will be asked to bear the cost of these discounts in the future. He says that approval of the contract without consideration of that issue would mean that the contract would be approved without consideration given to the true economic consequences to ratepayers.

Consistent with its view that Consumers' management should be permitted to enter into this special contract, the Commission also believes, as a general matter, that the utility should assume full responsibility for negotiating the discounted prices and that its shareholders should expect to absorb much, if not all, of any revenue shortfall caused by the pricing and other contract terms that the utility negotiates. In this case, the Commission has determined that approval of the contract depends on the revenue shortfall created by the difference between the contract price and the Rate T-2 floor being the responsibility of Consumers' shareholders and prohibiting the company from seeking to recover that amount from other customers. The treatment of the potential revenue shortfall created by the difference between the Rate T-2 floor and the transportation class cost of service will be addressed and resolved in the pending general rate case, where that revenue shortfall is already at issue.

Other Staff Concerns

[7] The testimony of the Staff witness and the Staff's initial brief state the Staff concerns with a somewhat different emphasis, which merits discussion.

The Staff says that approval of the special contract would commit Consumers to providing service to James River under a long-term, full service contract, at rates just above the short-run marginal cost of service, as calculated by Consumers, and possibly below the short-run marginal cost. The Staff says that, as a result, Consumers would never have the opportunity to recover its fully allocated costs of providing service to James River, even though, in the long- run, a utility must be allowed to recover its long-run costs in order to remain viable and to have the opportunity to earn a fair rate of return. Therefore, the Staff says that establishing rates for a long-term, full service contract based on the short-run marginal cost of providing service is bad policy. The Staff says that, at the very minimum, the Commission should consider the long- run costs of providing service to the specific customer as the basis for the rate and then allow only some discounting, at the utility's discretion, to meet short-term market challenges in order to maximize revenues. The Staff also says that short-run marginal cost should be the floor for that type of discounting. The Staff concludes, however, that setting rates for long-run contracts below the long-run cost institutionalizes the full discount, prevents the utility from taking actions to avoid costs that are variable in the long-run, and eventually requires that the discount be recovered from other customers or from shareholders.

The Staff says that the contract is a full-service contract that provides for all services available to any other Rate T-1 or Rate T-2 customer. The Staff says that there is nothing in the contract that would allow Consumers to offer the capacity used by James River to another customer, even if that customer were willing to pay the fully allocated cost of service. Therefore, the Staff says, that to add a new customer or to offer more service to other existing customers, Consumers would have to incur additional costs. The Staff acknowledges that Consumers had stated that it is not required to make any additional investment to serve this load, but he said that it must stand ready to do so if any additional investment is needed.

The Staff also says that there is a significant possibility that the contract rate may be below the short-run marginal cost. The Staff notes that, under Consumers' calculation, the difference between revenues and expenses is just $0.0372 per Mcf. The Staff states that this calculation includes some, but not necessarily all, of the short-run costs associated with James River. The Staff says that because of the schedule and limited information provided by Consumers, it was not possible for the Staff to conduct a study to determine the short-run variable costs associated with serving James River.

With respect to long-term costs, the Staff says that if the long-run cost of serving James River is the same as the embedded cost of serving the average transportation customer, then the cost of serving James River will ultimately exceed revenues by $1.2 million per year. The Staff says that because neither the Staff nor Consumers had conducted a study to determine the long-run marginal cost of serving James River, the exact amount of the revenue shortfall was not known. The Staff believes that many of the costs included in the fully allocated cost-of-service study would eventually have to be incurred to serve James River in the long run. The Staff says that to offset this potentially large revenue shortfall, Consumers proposed to collect a spread of only $140,450 [FN4] per year, assuming that Consumers' calculation of the variable cost is accepted. The Staff says that accepting such a large risk with such a meager potential return is unreasonable and imprudent, especially when James River's threat to bypass constitutes a permanent market challenge, unlike the threat from other fuels whose competitive position is subject to change. The Staff says that the Staff does not agree with Consumers' position that as long as the discounted rate covers the variable cost of providing service and makes some contribution to fixed cost recovery, the utility and its other customers are clearly better off with the special contract.

In its initial brief, the Staff adds that the decision on the contract should be based primarily on the economic effect on the local distribution company and its other customers, but it denies that the utility and its other customers would be better off in the long run if the Commission approves the special contract. Furthermore, it contends that approval of the special contract would set a bad ratemaking precedent and would violate sound policies established in Consumers' last general rate case. It says that approval of the company's request would have the Commission deviate from its clearly stated policy of requiring that all on-system transportation be performed pursuant to Rate T-1 or Rate T-2. It acknowledges that the Commission heard argument regarding the need for a flexible transportation rate that would allow Consumers to meet competitive challenges that were emerging. It notes that bypass was frequently mentioned as one of the alternatives available to system transportation customers. It says that the Commission addressed the need to meet the emerging competitive challenges by offering flexible pricing under Rate T-

2. It further argues that the Commission reinforced its sound policy of requiring on-system transportation to be performed under Rate T-1 or Rate T-2 with another sound policy of linking the range of rates to the cost of service. It says that the perceived cost of James River's bypass alternative should be used only to determine what price within the Rate T-2 range should be offered to James River.

In its initial brief, Consumers argues that it is irrelevant to argue that the rate for James River is discounted, but the service is not reduced, because the service provided to all Rate T-1 and Rate T-2 customers is the same. Only the price is different. It says that Rate T-2 is negotiable, to recognize that certain customers can demand a lower rate or they will leave the system, us James River can. It says that the value of the service to James River is lower and justifies the special contract rate. It also points out that, under Rate T- 2, it can already discount rates for long-term contracts below the fully allocated cost of service, which it says is necessary in certain competitive situations to prevent the loss of load, and those discounts may be permanent. It says that under both the special contract and Rate T-2, it may be unable to collect its fully allocated costs. It also adds that it can offer rates based on a fully-allocated cost of service to new customers, regardless of whether it continues to serve James River. It also says that Mr. Collin's testimony contradicts his testimony in the company's last gas rate case, Cases Nos. U- 8924 et al., where he proposed a $0.10 floor and recognized that fully allocated costs were not appropriate when the company does not have a monopoly position. In those situations, the company says, he admitted that the market would determine the price.

James River says that it makes no sense at this time to insist that all on- system transportation be performed under Rate T-1 or Rate T-2, especially because if the Commission does not approve the contract, there are no winners. It says that because it has the bypass option, a policy of linking rates to the cost-of-service is irrelevant. It suggests that the special contract rate should be analyzed in terms of the coverage of variable costs and the contribution to fixed costs, rather than on the basis of a fully allocated cost-of-service study. It says that recovery of fully allocated costs is not an alternative because it can and will bypass the system.

The Commission is not committed to a policy that transportation may occur only on Rate T-1 or Rate T-2, rather than pursuant to special contracts, particularly when the discount offered by Consumers to James River differs only in size, not character, from the discount already offered to Rate T-2 customers. For customers in unique circumstances, it may be necessary to be more flexible than Rate T-2 permits and, in the long-run, Consumers may find it necessary to offer further discounted prices to retain those customers on the system. At least initially, it is for Consumers' management to decide whether to pursue that course of action and to accept the risk that the contribution to fixed costs is inconsequential, although the Commission retains the authority to decide the ratemaking effects of the company's chosen course. In this case, the Commission cannot conclude that approval of the special contract will have any measurable effect on Consumers' financial viability, even if its shareholders are ultimately required to bear the entire discount that Consumers' management granted to James River. Finally, it does not appear that Consumers will be required to expend any large sums to serve new customers in the Kalamazoo area, even if James River remains a customer.

Discrimination

[8-11] The Attorney General says that, under relevant law, Consumers must offer this same rate to other similarly situated customers and, thus, Commission approval of a contract with a rate below the cost of service is not in other customers' best interest.

Consumers responds that the rates under the contract are not discriminatory because James River's competitive bypass alternative creates a reasonable distinction between James River and other transportation customers.

The possibility of discrimination in future dealings with requests for special contracts is not a reason to reject the special contract. The Commission must presume that Consumers negotiated the contract with a knowledge that it could not lawfully discriminate against other similarly situated customers. The Commission expects Consumers to act in accordance with applicable law. Customers remain free to pursue their remedies for unlawful discrimination.

Surcharges

[12] The Attorney General challenges the legality of the contract provision that exempts James River from future surcharges during the five-year term of the contract. He says that the Commission will be free in the future to set reasonable rates based on then-current facts and circumstances and that this contract provision cannot prevent the Commission from doing so in the future.

The Commission does not find that approving an exemption from future surcharges is different in any relevant manner than approving a rate below the Rate T-2 floor. Under both, the customer pays the rates required by the contract. In any event, the effect in this case, when new, large surcharges are not expected, appears to be minimal. Issues about discrimination against other customers can be addressed when and if they arise.

New Construction

[13] Staff witness Collins indicated a concern that proposed construction in the Kalamazoo area may not be specifically needed to serve James River, but may also not be needed if James River were to leave the system.

Mr. Miller and Mr. Biek explained that the James River load does not affect the company's planned construction and capital expenditures. Mr. Miller testified that the company does not project any need for system improvements for the portion of the company's gas distribution system that is used to serve James River for the next five years. Mr. Biek explained that the company's planned Kalamazoo area construction expenditures are unrelated to the James River load. Mr. Biek explained that the company does intend to install a new feed off its gas transmission system on the east side of Kalamazoo, but the James River load is served from the west side. Mr. Biek concluded that the proposed expansion of the transmission system will be required regardless of whether the James River load leaves the system. He also suggested that if the James River load is lost, the cost of the proposed construction in the Kalamazoo area may increase if the connection with Panhandle on the east side is used to meet James River's bypass load.

The record does not provide a basis to disagree with Consumers' assertion that retaining James River as a customer will not affect the company's planned construction during the term of the contract.

June 30, 1994 Letter Agreement

The Attorney General says that Consumers' conduct surrounding the letter agreement amounts to material misrepresentation that cannot be tolerated, especially when Consumers did not provide that agreement until the morning of February 1, 1995. He says that the agreement contains a number of incredible provisions and one unlawful provision: Consumers agreed to a six-month deadline for Commission action, Consumers agreed to build or arrange to have built the bypass pipeline if the six-month deadline passed, and Consumers agreed to provide gas transportation at rates below Commission-approved rates while the pipeline was under construction. He says that when Consumers filed the special contract, it falsely represented that the special contract contained the entire agreement of the parties. As a result, he says, the Commission cannot confidently say that Consumers has been candid in other areas of this proceeding.

As to the provision of the letter agreement by which Consumers agreed to effectively charge James River less than Commission-approved rates while the pipeline was under construction, the Attorney General says that it is unlawful and absolutely void. He therefore requests that the Commission order Consumers not to provide any service under the June 30, 1994 letter agreement.

Consumers says that the terms of the letter agreement are irrelevant to the issue of whether the special contract should be approved. It says that if any of the provisions of the letter agreement become operative and require Commission approval, the company will request the appropriate approval.

James River says that the Commission cannot order Consumers to abrogate its contractual commitments. It suggests that the parties to the contract can resolve any questions about the contract without legal guidance from the Attorney General.

The Staff requests that the Commission order Consumers to report its intentions with regard to the commitments in the letter agreement so that the Commission can decide if further proceedings are warranted.

The Commission concludes that the letter agreement is technically irrelevant to the issue of whether the special contract should be approved, but the existence of such an agreement and the manner in which it finally came to light do nothing to assist the Commission in deciding whether to approve the special contract. Similarly, the agreement and Consumers' conduct do nothing to enhance Consumers' credibility. Nevertheless, the Commission expects that the approval granted by this order will render the terms of the letter agreement irrelevant to Consumers' future dealings with James River. Still, it may bear repeating: Consumers may not charge or collect for a regulated service a rate or charge that varies in any manner from the rates and charges approved by the Commission. Further, Consumers shall keep the Staff informed of the status of its commitments in the letter agreement.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, R 460.17101 et seq.

b. With the ratemaking treatment discussed in this order, the special contract between Consumers and James River is reasonable and in the public interest, and should be approved.

THEREFORE, IT IS ORDERED that the special gas transportation contract between Consumers Power Company and James River Corporation is approved.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26.

By its action of February 23, 1995. FOOTNOTES

FN1 Consumers filed an application for leave to appeal the schedule set by the ALJ, which it later withdrew.

FN2 On December 21, 1994, James River filed a written agreement to these procedures.

FN3 The Attorney General points out that this alleged benefit does not accrue as a result of the special contract because it would also accrue if James River left the system. The Staff agrees and adds that Consumers is obligated to take reasonable and prudent actions to reduce the cost of gas to its sales customers, including not entering into unreasonable storage agreements with transportation customers.

FN4 Consumers later revised this amount to $174,200.

END OF DOCUMENT

Re Electric Services, Market Competition, and Regulatory Policies
Case No. 8678
Order No. 72136

Maryland Public Service Commission
August 18, 1995

***271** ORDER setting forth policy guidelines for the restructuring of the electric industry, in which the commission endorses a 'measured' approach to restructuring, noting that Maryland consumers currently enjoy electric rates below both national and regional averages. It finds that the state's electric industry is not in need of a dramatic fix, but would benefit from a process of sensible and progressive change designed to protect the interests of residential consumers, businesses, the utility industry, and other stakeholders.

Commission determines that retail wheeling is not in the public interest at the present time, but finds that competition at the wholesale level holds great promise for reducing electricity costs in Maryland. It observes that the Federal Energy Regulatory Commission (FERC) appears to be committed to open transmission access and urges members of the Pennsylvania-New Jersey-Maryland power pool and the Allegheny Power System to take an active role in FERC open access proceedings to ensure that utility ownership of transmission facilities does not inhibit competition. The state commission also expresses an intent to exercise its authority over Maryland utilities to open state-jurisdictional transmission facilities to wholesale competition while maintaining system reliability.

A competitive bidding policy is adopted for all future electric capacity needs. Commission finds that by restricting competitive bidding requirements to new capacity only, the potential for stranded investment is minimized. Utilities may participate in their own bid solicitations, subject to as yet to be formulated measures to prevent self-dealing. Like retail wheeling, divestiture of utility generating assets is deemed unnecessary at this time.

Commission declines to mandate any bidding set-asides or preferences for environmentally benign resources but recognizes its traditional role in fostering environmental protection and allows for the consideration of environmental factors in evaluating supply- and demand-side resource bids.

Commission finds that performance-based rate making (PBR) has the potential to provide significant benefits and expresses a willingness to consider PBR proposals on a utility-specific basis. However, it notes that PBR is unnecessary where competition exists because the rigors of the marketplace are sufficient to enforce efficiency. As such, it finds that current candidates for PBR proposals likely will include only transmission and distribution services and existing generation, rather than new generation, which will be subject to competitive bidding.

In rejecting proposals to immediately implement retail wheeling, the commission expresses concern that it could lead to cream-skimming of beneficial load, stranded investment, decreased reliability, underfunding of environmental and social programs, cost shifting, and negative impacts on municipal and cooperative utilities. It also notes that there are unresolved jurisdictional issues with respect to its authority to mandate retail wheeling.

Commission finds that utilities should be permitted to respond to competitive challenges through the judicious use of **special contracts** and flexible rates, as long as such a rate recovers customer-specific **variable costs** and some contribution to fixed costs. Moreover, the utility must demonstrate that (1) the special rate customer does in fact have a viable competitive ***272** alternative, and (2) the special rate does not result in an excessive rate increase for other customers. The commission also agrees to consider proposals to develop cost-based economic development rate plans.

Commission expresses a commitment to preserve the benefits of integrated resource planning, demand-side management, renewables, and social and environmental programs within the context of a more competitive environment. However, it emphasizes that it will not force utilities to purchase or implement uneconomic resources and will make every effort to ensure that Maryland utilities are not unduly or unfairly burdened with regulatory obligations that could hinder the move to a future industry paradigm -- e.g., retail competition. As such, any new social or environmental programs to be funded through utility rates will receive added scrutiny.

P.U.R. Headnote and Classification

1.

ELECTRICITY

s1

Md.P.S.C. 1995

[MD.] Industry structure -- Emerging market forces -- Transition to competition -- Generation market -- Federal policies.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

2.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Generation market -- Federal regulatory initiatives -- Public Utility Regulatory Policies Act -- Energy Policy Act of 1992 -- Federal notice of proposed rulemaking as to open access.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

3.

ELECTRICITY

s1

Md.P.S.C. 1995

[MD.] Industry structure -- Emerging market forces -- Transition to competition -- State investigations and inquiries.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

4.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Industry restructuring -- State investigations and inquiries.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

5.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Industry restructuring -- Factors driving competition -- Excess capacity -- Locational competition -- Rate/cost divergence -- Interfuel competition -- Deregulation trends -- Global economy.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

6.

ELECTRICITY

s1

Md.P.S.C. 1995

[MD.] Industry restructuring -- Commission policy -- 'Measured' approach.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

7.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Industry restructuring -- Wholesale competition -- Open access to transmission -- State and federal policy.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

8.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Generating plants and interconnected systems -- Operating practices -- Impact of industry restructuring -- Wholesale competition -- Open access to transmission -- Voluntary pooling -- State and federal policy.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

9.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Generating plants and interconnected systems -- Industry restructuring -- Wholesale competition -- Corporate reorganization -- Separation of generation from transmission and distribution functions -- Discussion.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

10.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Industry restructuring -- Wholesale competition -- Corporate reorganization -- Separation of generation from transmission and distribution functions -- Discussion.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

11.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Operating practices and efficiency -- Resource procurement -- Industry restructuring -- Competitive bidding for future capacity needs -- Wholesale competition -- ***273** Minimization of stranded investment.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

12.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Wholesale competition -- Competitive bidding for future capacity needs -- Protection against self- dealing -- Minimization of stranded investment -- Industry restructuring.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

13.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Operating practices and efficiency -- Resource procurement -- Future capacity needs -- Competitive bidding scheme -- Environmental considerations.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

14.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Retail competition -- Retail wheeling -- Benefits and burdens -- Public interest determination -- No present need for retail wheeling.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

15.

ELECTRICITY

s1

Md.P.S.C. 1995

[MD.] Retail competition -- Retail wheeling -- Benefits and burdens -- Public interest determination -- No present need for retail wheeling.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

16.

ELECTRICITY

s2

Md.P.S.C. 1995

[MD.] Commission jurisdiction -- Power to mandate retail competition -- Discussion.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

17.

SERVIC

s320

Md.P.S.C. 1995

[MD.] Electric -- Retail wheeling -- Benefits and burdens -- Public interest determination -- No present need for retail wheeling.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

18.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- Special contracts and flexible rates -- Economic development rates -- Guidelines.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

19.

RATES

s140

Md.P.S.C. 1995

[MD.] Factors affecting reasonableness -- Competition -- Special contracts and flexible rates -- Electric utilities.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

20.

RATES

s166

Md.P.S.C. 1995

[MD.] Factors affecting reasonableness -- Solicitation of business -- Economic development rates -- Electric utilities.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

21.

RATES

s322

Md.P.S.C. 1995

[MD.] Electric rate design -- Load retention -- Special contracts and flexible rates -- Economic development rates.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

22.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Operating practices -- Load attraction and retention -- Economic development rates -- Special contract and flexible rates -- Guidelines.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

23.

PUBLIC UTILITIES

s73

Md.P.S.C. 1995

[MD.] Electric -- Public service regulation -- Industry restructuring -- Performance-based rate making (PBR) -- Monopoly services -- Transmission and distribution -- Existing generation -- Inapplicability of PBR to new generation.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

24.

MONOPOLY AND COMPETITION

s54

Md.P.S.C. 1995

[MD.] Electric services -- New generation -- Competitive bidding for future capacity needs -- But inapplicability of performance-based rate making -- Industry restructuring.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

25.

RATES

s321

Md.P.S.C. 1995

[MD.] Electric rate design -- Performance-based rate making (PBR) -- Monopoly services -- Transmission and distribution -- Existing generation -- Inapplicability of PBR to new generation.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

26.

ELECTRICITY

s4

Md.P.S.C. 1995

[MD.] Integrated resource planning -- ***274** Renewables -- Demand-side management -- Environmental concerns -- Social programs -- Continued commitment -- Industry restructuring.

Re Electric Services, Market Competition, and Regulatory Policies

P.U.R. Headnote and Classification

27.

CONSERVATION

s1

Md.P.S.C. 1995

[MD.] Electric utility -- Integrated resource planning -- Demand-side management -- Continued commitment -- Industry restructuring.

Re Electric Services, Market Competition, and Regulatory Policies

BY THE COMMISSION:

I. INTRODUCTION

A. ADMINISTRATIVE HISTORY

1. Conduct of the Proceeding

On its own motion, the Commission issued Order No. 71459 on September 19, 1994, instituting this proceeding to inquire into regulatory and competitive issues affecting the electricity industry in Maryland. Order No. 71459 also posed various questions related to important issues surrounding electricity restructuring. In addition, to further the identification of issues appropriate to the investigation, we directed the Staff of the Commission ('Staff') to prepare a discussion paper describing issues which warrant analysis and comment. On November 1, 1994, this discussion paper, entitled New Directions in Electric Regulation, was filed with the Commission and sent to all of the State's electric utilities and other interested persons.

Finally, Order No. 71459 requested the State's electric utilities and other stakeholders to comment on issues relevant to the inquiry, specifically those posed in the Order or described by Staff in its discussion paper. The Order then set procedural dates for the filing of initial and reply comments, a legislative-type public hearing, and final comments.

After revision to the procedural schedule, the Commission received initial comments on January 17, 1995, and reply comments on February 21, 1995. The legislative-type public hearings were held on March 7-10, 1995, and final comments were filed on April 4, 1995.

2. Participants

The following parties participated in this proceeding: Potomac Electric Power Company; Delmarva Power & Light Company; Potomac Edison Company; Baltimore Gas & Electric Company; PECO Energy Company; Maryland People's Counsel; the Staff of the Commission; Maryland Office of the Attorney General (representing the Departments of Agriculture, Economic and Employment Development, Environment, Natural Resources, Transportation, the Maryland Energy Administration, and the Maryland Office of Planning); U.S. Department of Energy and the U.S. Environmental Protection Agency; Department of Defense and the Federal Executive Agencies; Westvaco Corporation; Bethlehem Steel Corporation, General Motors Corporation, the Maryland Industrial Group, and the Electricity Consumers Resource Council; Enron Power Marketing, Inc.; Mid-Atlantic Independent Power Producers; Southern Maryland Electric Cooperative, Inc. and Choptank Electric Cooperative, Inc.; City of Hagerstown, MD and the Town of Williamsport, MD; Mayor and Council of Berlin; Thurmont Municipal Light Company; Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc. on behalf of Somerset Rural Electric Cooperative, Inc.; Maryland SEED Campaign; Maryland Safe Energy Coalition; Center for Energy and Economic Development; International Brotherhood of Electrical Workers; Jane F. Rissler, Ph.D.; Mr. David Lapp; Dr. Dorothee Einstein Krahn; Ms. Patricia S. Lane (also representing the League of Women Voters of Baltimore City); Ms. Anneke Davis; and Mr. Anthony Dunn.

B. BACKGROUND

1. Federal Policies

[1-5] It is widely recognized that the electric utility industry is in a period of

substantial ***275** change. Some of this change is being fostered by pro-competitive federal legislation and regulation, which is attempting to recognize the emergence of market forces in what has been a largely monopoly industry. These changes relate primarily to opening the electricity generation market to competition.

Historically, the generation of electric energy was thought to be a natural monopoly. A natural monopoly is said to exist when costs over the relevant range always decline as production increases, and technology is such that the existence of more than one supplier leads to a wasteful duplication of capacity. The assumed existence of a natural monopoly was the main justification for permitting utilities to monopolize generation in their service territories, subject to comprehensive rate-base/rate-of-return regulation.

Beginning in the mid 1970's, a series of domestic oil shortages, escalating energy prices, and concern for the environment, helped trigger the application of new technologies, laws, and regulations that have removed most, if not all, of the conditions of natural monopoly in the generation of electricity.

Central to the removal of these natural monopoly conditions was the enactment of the Public Utilities Regulatory Policies Act of 1978 ('PURPA'), [FN1] which helped usher in an era of generation competition. PURPA required utilities to purchase power from qualifying facilities ('QF's') at rates equal to or less than the utilities' avoided cost. To certify as a QF, a plant had to meet certain size and ownership criteria, and utilize renewable or cogeneration technologies.

For the first time, utilities were required -- under defined conditions -- to purchase capacity and energy from generating sources not owned or controlled by themselves. The States were given considerable latitude in implementing PURPA. Although there is currently a spirited debate regarding the overall success and continued economic efficacy of PURPA, it is nonetheless clear that the Act was instrumental in opening the generation market.

After the QF alternatives were made available through PURPA, other non- traditional power suppliers began to emerge, such as independent power producers and power marketers. These entities had some success in establishing a foothold in the generation market. However, they often complained of utility control of bottleneck transmission services, which they claimed inhibited their ability to deliver power to potential customers in some cases. Another impediment was the Public Utility Holding Company Act's ('PUHCA') [FN2] restrictions on ownership of generation businesses.

To remove some of these PUHCA restrictions, as well as eliminate some basic transmission service obstacles to wholesale competition, the Congress enacted the Energy Policy Act of 1992 ('EPAct'). [FN3] This act created a new type of generation competitor -- the Exempt Wholesale Generator -- which is exempt from certain PUHCA ownership restrictions. More importantly, the EPAct also significantly expanded the Federal Energy Regulatory Commission's ('FERC ') authority to order transmission services under Section 211 of the Federal Power Act. [FN4]

Pursuant to this new legislative mandate, the FERC began an aggressive campaign to foster competition among generators at the wholesale level. The FERC proceeded to issue a series of orders, policy statements, proposed rulemakings, and inquiries, culminating in the notice of proposed rulemaking ('NOPR') on open transmission access. [FN5] The FERC has stated, '[o]ur goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa.' [FN6]

In the Open Access NOPR, the FERC indicates that utility control over transmission services is the major impediment to a competitive generation market. As such, the

Open Access NOPR seeks to require all utilities to offer non-discriminatory transmission services that are comparable to those which they provide themselves. [FN7] The NOPR also describes a plan for addressing stranded costs. [FN8]

In sum, while much remains to be resolved at the federal level, through the Open Access NOPR and other forums, the FERC has already made its decision to foster wholesale generation competition -- the debate now is limited, on the ***276** federal level, to the best way to achieve this goal. In the individual States, such as Maryland, the FERC's determination plays a crucial role as public utility commissions wrestle with all issues pertaining to electric industry restructuring.

2. State Investigations and Inquiries

The Public Service Commission of Maryland is far from alone in exploring the changes in the electricity industry. Currently, several other state commissions have instituted similar proceedings, including those in Iowa, Pennsylvania, Ohio, Wisconsin, Illinois, New York, California, Michigan, and Massachusetts. The Connecticut Department of Public Utility Control has already issued an order, in which it found retail wheeling not to be in the public interest at this time. [FN9]

Moreover, many state legislatures have addressed, or are in the process of addressing, these issues -- including California, New Jersey, Texas, and Nevada. The New Hampshire legislature has even passed a law requiring the New Hampshire Public Utilities Commission to establish a pilot retail wheeling program and a legislative task force to study restructuring of the State's power industry. By the time this order is issued, many other states will likely be engaged in exploring these issues.

The California Public Utilities Commission ('CPUC') issued its Order Instituting Rulemaking and Order Instituting Investigation, Docket Nos. R.94- 04-031 and I.94-04-032, on April 20, 1994. These highly controversial orders instituted a proceeding to explore competitive options and proposed implementation dates for reform.

Roughly a year later, on May 24, 1995, the CPUC issued two new proposals for comment. The majority proposal would restructure California's electric industry by virtual direct access through a voluntary wholesale pool with retail competition through physical, bilateral contracts, not sooner than two years after the pool begins. An alternative proposal was offered which advocates consumer choice through direct access, whereby consumers can enter directly into individual agreements with power producers. The CPUC indicated that it will accept comments and hold hearings on the proposals. Following these proceedings, the CPUC will issue a final policy decision, unless the California legislature intervenes.

The Michigan Public Service Commission ('MPSC') took a cautious first step in authorizing a limited retail wheeling experiment in Re Association of Businesses Advocating Tariff Equity, Case No. U-10143, issued April 11, 1994. On June 19, 1995, the MPSC issued its final order in this case, in which it determined specific unbundled retail wheeling rates. However, the experiment is not triggered until either of the State's two largest utilities initiate a new capacity solicitation.

As is clear from the above, some states are further along than others in addressing restructuring issues; however, no state has moved far beyond the investigation stage. This includes the other PJM states. [FN10] To address any regional implications of reform, Maryland and the other PJM states have recently begun a dialogue to cooperatively explore regional restructuring issues.

3. Other Factors Driving Competition

As noted in the Staff's discussion paper, several other factors, in addition to those discussed earlier, are driving competition in the electricity industry. These factors include: excess capacity in the Mid-Atlantic region, locational competition (i.e., competition for loads within the State, between states, and even internationally), the divergence of utility rates from costs, and interfuel competition (i.e., competition between electricity and gas, oil, and other fuels). Other influencing factors are the deregulation experiences with other industries in the U.S. (e.g., natural gas, telecommunications, airlines, and transportation), the deregulation of the electricity industry in other countries, and intensifying competitive business pressures related to an emerging global economy.

C. SUMMARY OF THE PUBLIC SERVICE COMMISSION OF MARYLAND'S APPROACH TO RESTRUCTURING

***277** [6] It is against the foregoing background that the Commission is issuing this order. The Commission intends to take a measured approach to restructuring Maryland's electric utility industry. Maryland consumers currently enjoy electricity rates below both national and regional averages. [FN11] Moreover, Maryland's electricity rates are globally competitive compared to those in most other industrialized countries. [FN12] Unlike some other states, there has been no clamor among Maryland consumers over exorbitant electricity rates. Also, unlike many other states, Maryland's electricity rates are not inflated by an abundance of expensive nuclear power plants or many high-cost PURPA contracts. As such, Maryland's electric utility industry is not in need of dramatic fixes at this time. On the other hand, the Commission does see the need to begin a process of sensible and progressive change, designed to protect the interests of our residential consumers, businesses, the utility industry, and other stakeholders.

This proceeding has been extremely valuable in providing the Commission with an abundance of information reflecting many different perspectives. While the views of many of the commenters are sharply divergent, it is nonetheless possible to discern significant areas of consensus. For example, most commenters agree that the electricity industry in Maryland is in relatively good shape. Also, most agree that there are many benefits to be gained from restructuring to encourage competition. However, the commenters differ sharply on the extent of needed reforms, with opinions ranging from minor readjustments of the industry to significant restructuring. Additionally, many of the commenters note numerous unresolved issues on both the Federal and State levels.

Based on careful analysis and consideration of the record in this proceeding, the Commission will provide the stakeholders in the State's electric utility industry with broad guidelines to begin laying the foundation for competition in Maryland. This Order discusses the following sometimes overlapping major issues: wholesale competition and competitive bidding; retail competition; special contracts and rate flexibility; performance-based ratemaking ('PBR'); and integrated resource planning ('IRP'), demand-side management ('DSM'), renewables, and social programs.

II. COMMISSION ANALYSIS

A. WHOLESALE COMPETITION AND COMPETITIVE BIDDING

1. Wholesale Competition

a. Position of the Parties

The overwhelming majority of commenters support wholesale competition. These commenters assert that a competitive wholesale generation market will likely lead to greater efficiencies and lower costs to consumers. Four of five investor-owned utility ('IOU') commenters support wholesale competition. The Potomac Electric Power Company ('PEPCO') notes that there is a lively competitive market for incremental generating capacity; however, it maintains that there are transmission constraints inhibiting this market.

PEPCO also offers a proposal for reorganizing itself into a generating division ('G Division') and a transmission and distribution division ('T&D Division'). The T&D Division (which would remain regulated) would enter into a performance-based, contract-like arrangement with the G Division, the terms of which would be subject to Commission review. This arrangement would initially cover all of the PEPCO generating capacity allocated to the Maryland jurisdiction, but the T&D Division would make no commitments with respect to any future G Division-built capacity. In addition, there is a mechanism for the T&D Division to gradually shed its initial commitment to the G Division. PEPCO points out that implementing its plan will lead, gradually, to the T&D Division being able to meet all of its generation needs from the competitive wholesale market.

The Delmarva Power & Light Company ('Delmarva') also supports wholesale competition. However, Delmarva, unlike the other utility commenters, urges the Commission to also explore retail wheeling.

The Baltimore Gas & Electric Company ***278** ('BGE') supports the relaxation of regulation in the bulk power market, and urges the Commission to articulate a vision which embraces wholesale competition. BGE points out that there is not a large stranded investment concern with wholesale competition, and that the financial markets already assume that there is going to be a movement toward additional bulk power competition. BGE also notes, however, that such risks may not be completely factored in by the financial markets.

While BGE supports wholesale competition, it also emphasizes the need to maintain reliability, and believes that additional changes are necessary to reach the goal of a fully competitive wholesale market. As such, BGE urges the Commission to participate in all FERC proceedings that could potentially impact Maryland electric utilities, and to become actively involved in MAAC [FN13] discussions.

The PECO Energy Company ('PECO'), the only non-Maryland regulated IOU to participate in this proceeding, supports wholesale competition. PECO believes that developments at the wholesale level will continue to provide incentives to utilities to keep marginal costs low, and to produce all available efficiencies.

The Maryland People's Counsel ('MPC'), Staff, and the Maryland Agencies [FN14] support taking advantage of opportunities now available on the wholesale market. Both Staff and the Maryland Agencies specifically advocate further study of PEPCO's proposal to structurally separate transmission and distribution ('T&D') from generation.

The U.S. Department of Energy and the U.S. Environmental Protection Agency ('DOE and EPA') [FN15] assert that potential gains from competition are more clear with respect to the wholesale market than to the retail market. Both agencies note that three-fourths of the cost of a delivered kilowatt hour is related to generation, including fuel costs, and, therefore, the savings achieved here are apt to be considerably larger than the savings on the retail side. DOE and EPA also point out that federal/state jurisdictional concerns are not as great on the wholesale level as they are on the retail level. Lastly, these two federal agencies urge the Commission to encourage PJM to be more market-driven.

Enron Power Marketing, Inc. ('EPMI') supports a competitive wholesale generation industry, but strongly opposes the adoption of a mandatory British- style poolco system. [FN16] EPMI argues that such a poolco would be simply a new regulatory monopoly subject to the abuses of utility market power. However, EPMI states that it would not oppose voluntary poolcos.

The Mid-Atlantic Independent Power Producers ('MAIPP') also support competition in bulk power supply markets. MAIPP contends that there is a mature market of competitors who are ready and able to provide generation service, but that they currently face market barriers. MAIPP is particularly concerned about the potential for abuse of market power by incumbent utilities, and stresses the need for more open access to the transmission grid. MAIPP advocates mitigating investor-owned utility market power by separating generation from T&D. MAIPP urges the Commission to 'level the playing field' in order to encourage wholesale competition. Lastly, MAIPP does not support PEPCO's reorganization proposal, as it believes it falls short of neutralizing utility market power, primarily because it would tie all current retail customers to PEPCO's G Division for a considerable period of time rendering them captive to PEPCO's pricing.

Likewise, both the Southern Maryland Electric Cooperative, Inc. and the Choptank Electric Cooperative, Inc. ('SMECO and CEC') support wholesale competition and improved retail rate regulation, but are concerned with obtaining equal and open access to generation over transmission lines. To this end, SMECO and CEC urge the Commission to encourage improved transmission access, and to consider extending more fully the benefits of access to the existing pool structure to T&D utilities like SMECO and CEC. These electric cooperatives also note that federal reforms are only now being implemented by the FERC, and, therefore, the wholesale market needs time to mature.

The small municipal utilities of the City of Hagerstown, MD and the Town of Williamsport, MD ('Hagerstown and Williamsport'), the Mayor and Council of Berlin ('Berlin'), and ***279** the Thurmont Municipal Light Company ('Thurmont ') all support wholesale competition, but concur with SMECO and CEC that the bulk power market needs time to mature. The Pennsylvania Rural Electric Association, et al. [FN17] also supports wholesale competition. The small municipals urge the Commission to take into consideration the unique characteristics of small electric utilities in any move to increased competition. Furthermore, Berlin and Thurmont also advocate further study of PEPCO's proposal to separate T&D from generation.

The Maryland SEED Campaign ('SEED') [FN18] supports the exploration of some wholesale wheeling options, but only if they are combined with aggressive integrated resource planning and real incentives for energy efficiency and renewable technologies.

Though support for wholesale competition reflects the clear consensus of the commenters, it is not unanimous. For instance, the Potomac Edison Company ('PE ') does not fully endorse wholesale competition at this time. PE argues that deregulation of the generation sector is premature and could threaten reliability. PE also asserts that such deregulation would merely result in a movement towards a regional average price, and would also result in increased financial risks leading to increased utility capital costs. PE contends that fair resolution of reliability concerns and issues pending at the FERC are necessary prerequisites to the deregulation of the generation sector. Lastly, PE maintains that if competition is to be endorsed, it should be done in accordance with its suggested poolco proposal. [FN19]

The Industrial Users [FN20] are the only party to oppose wholesale-only competition flatly. The Industrial Users believe wholesale-only competition to be an oxymoron, because as long as ultimate consumers are captive to their supplier, that supplier can shift planning and investment risk to those customers. In sum, the Industrial Users support retail competition. Anything short of this is unsatisfactory to them.

b. Commission Findings

[7-10] After careful review of the extensive record in this proceeding, the Commission is of the opinion that competition at the wholesale level holds great promise for reducing electricity costs in Maryland.

It is our view that there are many benefits to be gained from supporting wholesale competition. For example, there is excess, relatively inexpensive power currently available in the bulk power market. This situation exists because some electric companies in the Mid-Atlantic region are currently overbuilt, and in some cases are not able to earn a return from native load customers on the excess plant. Consequently, the power from these plants is available at very attractive prices. Other factors include: advances in generation technologies; the current low price of natural gas; and the emergence of aggressive non-utility generators ('NUG's'). The existence of many potential wholesale suppliers is evident from recent bids conducted under the purview of this Commission. [FN21] Maryland utilities are encouraged to tap these generation resources for the benefit of all Maryland electricity consumers whenever prudent and cost-effective.

Some commenters assert that utility control over transmission inhibits access to the competitive generation market. This is a legitimate concern which is currently being addressed by the FERC. The FERC has issued its Open Access NOPR, which seeks to implement open access transmission tariffs based on the principle of comparability, as stated in the case of American Electric Power Service Corporation. [FN22] The intention is to eliminate any unfair utility advantages accruing from control of the transmission grid. While this rulemaking is only in the comment stage, FERC's companion order -- which provides guidance in pending and future transmission access cases -- makes clear that the FERC intends to apply its comparability standards in advance of a final rule in the Open Access NOPR. [FN23]

The Commission believes the FERC's resolve to eliminate concerns with transmission access in the competitive bulk power market is clear from the Open Access NOPR and its recent orders. The Commission generally supports the FERC's efforts in this area. However, we also intend to promote vigorously the ***280** concerns of Maryland consumers, utilities, and other stakeholders in the NOPR process, and in the implementation of any open access tariffs in the interim.

On the State level, the Commission will exercise its authority over Maryland utilities to open State-jurisdictional transmission facilities to wholesale competitors. However, in exercising such authority, we will maintain the reliability of the State's electricity system. We are convinced that the reforms envisioned in this Order will not jeopardize reliability.

The Commission will take this opportunity to address two other issues of importance in the area of wholesale competition. Voluntary power pooling, as well as other forms of utility coordination, play a vital role in the provision of electricity in Maryland. For example, much of Maryland's electricity needs are served by members of either the PJM power pool or the Allegheny Power System ('APS'). [FN24] While there are important distinctions between these two organizations, the benefits they provide -- notably increased reliability and decreased costs -- are similar. The Commission believes it is important to retain these benefits in the move to a more competitive wholesale market. In fact, the Commission believes that power pools may be useful vehicles in the move towards increased wholesale competition.

The Commission commends PJM for its comments in the FERC's Inquiry Concerning

Alternative Power Pooling Institutions Under the Federal Power Act. [FN25] These comments indicate that the PJM Members are developing a package of changes aggressively, including a price-based spot energy market, comparable regional transmission services available to all participants, unbundled control area services, and a coordinated planning process; all of which are intended to provide an open competitive regional market on a reliable basis. [FN26]

The Commission urges both PJM and APS to take a similarly active role in the FERC's recent Open Access NOPR. In the NOPR, the FERC asserts that it will apply its open access policies to power pools, but it acknowledges that power pools raise complex issues. The FERC specifically solicits comments on how to implement the NOPR for power pools. The FERC also indicates that after it has received comments on this matter, and before a final rule is adopted, it intends to hold technical conferences with power pools to discuss implementation issues. [FN27] We fully expect PJM and APS to participate in these proceedings. In the meantime, the Commission has intervened and will participate in the Duquesne Light Company's requests of PJM and APS for transmission service, which are currently pending at the FERC. [FN28]

Lastly, the Commission strongly encourages PEPCO to continue to study its restructuring proposal. The Commission is intrigued with PEPCO's proposal, and would like to see it developed further. We urge PEPCO to keep the Commission informed of its progress. We also encourage the State's other electric utilities to consider their own particular competitive positions, and to develop specific proposals accordingly.

2. Competitive Bidding

a. Position of the Parties

Two IOU commenters support a standard competitive bidding policy. While PE believes that deregulating the generation sector is premature, it does support the adoption of a standard policy of competitive bidding for new capacity and DSM resources. PE also believes that a utility should be permitted to compete in its own bid.

PE also emphasizes several other factors that it believes should be taken into consideration in any competitive bidding scheme. These factors include: the importance of the utility building some minimum capacity; flexibility; the risks associated with purchased power; conflicts with competitive bidding schemes in other states; and non-price factors. Moreover, PE notes that it is often difficult for a utility to compete in a bid because utilities, unlike NUG's, are not permitted to finance projects with a high degree of leverage.

PECO also urges the Commission to encourage or require competitive bidding by utilities for new resource needs as a means of fostering competition in the wholesale market.

***281** Likewise, the Maryland People's Counsel urges the Commission to require all Maryland electric utilities either to use a competitive bidding process for all future supply resources or affirmatively to demonstrate why the particular supply-side need should not be bid. MPC also believes the Commission should consider requiring utilities to replace existing generation through bulk power solicitations.

MPC asserts that competitive bidding will enlarge the number of options that can be evaluated simultaneously, and, therefore, is superior to negotiation with individual developers. Moreover, the bid can incorporate interdependent secondary elements, such as environmental factors, flexibility, and reliability concerns. MPC also believes that all-source bidding should encompass DSM-type bids along with supply-side bids.

MPC is, however, concerned with utilities favoring their own bid in a solicitation (i.e., self-dealing). To insure against this, MPC suggests the use of an independent third party to evaluate bids. In any event, MPC does not believe the divestiture of generation assets is necessary.

Staff also supports mandatory all-source competitive bidding, including demand measures, for all incremental resources. In addition, Staff asserts that the Commission could encourage offers from conservation projects or low emissions technologies.

Staff maintains that the key issue is whether to permit the utility to participate in its own bid, as it would be extremely difficult to ensure fairness. Staff suggests the use of separate utility generating subsidiaries, but acknowledges that this might not be sufficient. In any event, Staff does not support 'flash cut' divestiture at this time, but would consider gradual divestiture.

The Maryland Agencies suggest that the Commission issue a proposed rule on the subject of competitive bidding guidelines.

The Industrial Users advocate retail wheeling, but to the extent that the vertically-integrated industry remains, they argue that utilities should always competitively procure incremental resources. The Industrial Users also submit that existing rate-based units should be subject to bidding. However, the Industrial Users stress that substantial market barriers remain that continue to stifle the independent power industry to the advantage of incumbent utilities. Further, to ensure against self-dealing, the Industrial Users assert that utilities should only be permitted to bid in their own solicitation if their customers are allowed direct access to other generators, or if all generation assets are divested. Lastly, the Industrial Users emphasize that they do not believe generation to be a natural monopoly, and, therefore, 'real' competition -- not a regulated competitive bidding scheme -- is ultimately desirable.

The Mid-Atlantic Independent Power Producers also support competitive bidding, and argue that any potential concerns (e.g., risk of project failure) can be handled contractually. Moreover, MAIPP endorses requiring utilities to divest themselves of their generation assets to protect against self-dealing.

In addition, both SMECO and CEC and Hagerstown and Williamsport support the use of competitive bidding.

SEED supports the exploration of competitive bidding, but emphasizes that any scheme must include measures for assessing the long-term environmental costs associated with energy production.

Lastly, Mr. David Lapp notes his support for bidding, but urges the Commission to consider divestiture, as utilities have an incentive to choose their own generation over that of competitors.

Except for PE, the State's major investor-owned utilities are opposed to adoption of a competitive bidding policy. PEPCO does not support a standard policy requiring competitive bidding for incremental resources, citing differences among the utilities in the State. However, PEPCO argues that if a bidding scheme is adopted, utilities should be permitted to participate in their own bids. PEPCO opposes the divestiture of generation assets unless self- dealing becomes a major problem.

Delmarva also opposes a standard competitive bidding policy, because it does not believe that there should be any constraints placed on the way it goes about acquiring generation sources in a deregulated market. Further, ***282** Delmarva asserts that it would take years to see any benefits from competitive bidding, and as such, the Commission should concentrate on encouraging a fully competitive market. However, Delmarva does acknowledge that there are some benefits to bidding, and argues that utilities should be permitted to participate in any bidding scheme adopted by the Commission. Lastly, Delmarva does not support divestiture of generation assets.

Likewise, BGE does not believe the Commission should mandate the exclusive use of competitive bidding for new generation. Rather, BGE suggests alternatives such as competitive negotiation. BGE also opposes divestiture of its generation assets.

The towns of Berlin and Thurmont oppose an immediate switch to a competitive bidding process. These small municipal utilities contend that the bidding process is expensive, and might be especially burdensome for smaller municipals. As such, they urge the Commission to allow a period of transition whereby small municipals would be permitted flexibility in complying.

b. Commission Findings

[11-13] The Commission believes that competitive bidding provides the best means of obtaining the very real benefits of a competitive bulk power market for Maryland electricity consumers. The Commission agrees with Staff that, over the short-term, competitive bidding will take advantage of the current Mid- Atlantic region's surplus of power. Further, over time it will provide the discipline of a competitive market to the electric power generating sector. The Commission, however, will not adopt standardized competitive bidding guidelines in this proceeding. Rather, we will develop guidelines on a utility-by-utility basis.

All of the State's utilities are different, and, therefore, what works for some will not work for all. Additionally, circumstances and conditions change over time, and as such, it is unwise to develop rules today that may not be applied for some time. Accordingly, at this time the Commission will provide a framework that all utilities and stakeholders can use in future discussions and negotiations.

First, all new capacity needs will be subject to competitive bidding. Bidding will not be mandatory in all cases, but utilities will bear the burden of affirmatively demonstrating why a particular capacity need should not be bid. We decline to subject existing capacity to bidding. A new-capacity-only policy will allow reform to occur gradually. Importantly, it will also minimize stranded investment concerns, as existing utility plant will not be subject to competition from alternate suppliers. As such, it is unnecessary for the Commission to address the issue of stranded cost recovery at this time.

Utilities will be required, as part of their IRP process, to notify the Commission in a timely manner of the need for new capacity resources. It is the responsibility of the utility to allow for sufficient time to both develop and carry out a bid.

Second, the Commission has decided that utilities will be permitted to participate in their own bids. We understand fully that utilities may have a conflict of interest in both participating in and evaluating a bid. The Commission is confident that it is capable of insuring against self-dealing. Measures will be formulated for each utility at the time the utility develops and implements a bidding process. In this regard, we do not believe that utility divestiture of generation assets is necessary at this time.

Third, the Commission also realizes that utilities may enjoy other advantages in a bid, such as exclusive access to information and the power of eminent domain, although this advantage is at least partially offset by the NUG's ability to finance projects with a high degree of leverage. The Commission will not tolerate the concealment of information necessary for effective bidding on a utility's request for proposals, and will take steps to ensure that all competitors have access to such information. We will also take steps to ensure that confidential utility information is not divulged to the utility's detriment. The Commission also is confident that it can deal with any other unfair advantages that may become evident when a particular utility's solicitation is developed and implemented.

Fourth, price will not be the only factor considered in a bid. Other important factors to ***283** be considered include: the probability of successful project completion; reliability of delivery during the entire contract period; ease of integrating the purchase into the buying utility's operations; and flexibility to respond to changing circumstances (e.g., contract reopeners and variable energy takes). This last factor is particularly important, as the Commission is well aware that power purchase contracts may become uneconomic in the future due to inaccurate price forecasts. The preceding list is for illustrative purposes only; there will likely be other factors to consider in specific cases.

Moreover, we decline at this time to mandate any set-asides or preferences for environmentally benign resources, such as renewable generation technologies or conservation measures. The Commission, however, recognizes its traditional role in fostering environmental protection. The Commission's enabling legislation requires it to consider the conservation of natural resources and the preservation of environmental quality in its regulation of this State's public service companies. [FN29] In conducting their business, the State's electric utilities also have an affirmative statutory duty to give consideration to the conservation of natural resources, energy efficiency, and the quality of the environment. [FN30] In this era of increasing competition, we will not require this State's utilities to purchase resources at uncompetitive prices. However, as previously noted, price is not the only factor to be considered in a bid. As such, we believe it is appropriate to consider environmental factors alongside others considered in evaluating a bid.

Related to the above, the Commission will permit DSM resources to compete against supply-side resources. DSM resources will not be given any preference in a bid. However, these resources are environmentally clean and conserve energy. These are important factors which should be considered in any evaluation.

Lastly, we are aware that competitive bidding may affect the State's small municipal and cooperative utilities differently than the larger IOU's. The Commission intends on taking these unique characteristics into consideration fully in adopting any reforms. The Commission reiterates that each utility's bidding scheme will be individually developed at the time of its need for new capacity resources. One of the main objectives of such a policy is to address utility-specific concerns.

The Commission has instituted competitive bidding on a case-by-case basis in the past. [FN31] In this order, we are breaking with this past practice by adopting a competitive bidding policy for all future capacity needs. The Commission believes that the above guidelines provide a framework for future competitive bidding.

B. RETAIL COMPETITION

1. Position of the Parties

Most of the commenters in this proceeding oppose the adoption of retail competition at this time. [FN32] These commenters describe many drawbacks of retail competition, and conclude that these problems outweigh its benefits. Many of these commenters also believe that retail competition will not provide benefits over and above that which can be achieved through wholesale competition.

All of the investor-owned utility commenters, except Delmarva, oppose retail competition. PEPCO, PE, and BGE identify serious problems related to retail wheeling, including: (1) the need to redefine or eliminate the utility's current obligation to serve all customers in its service territory; (2) the lack of reciprocity in surrounding states; (3) the issue of stranded costs; (4) concerns over decreased reliability; (5) the inability of utilities to bear the burden of special taxes and environmental/social programs; and (6) legal issues related to jurisdiction.

PE also stresses uncertainty at the federal level, and urges the Commission not to make any decisions until federal policies are in place. To this end, PE urges the Commission to monitor policy development at the FERC. Further, PE is concerned with the shifting of costs to captive customers and the 'cream- skimming' of its load by other utilities, which it claims would occur in a retail wheeling environment.

BGE contends that retail competition will ***284** not provide benefits over and above those achieved through wholesale competition, as the majority of market-efficiency benefits are found in the generation sector. In addition, any of the alleged benefits of retail competition would be tempered by increases in utility capital costs due to increased business risk.

PECO maintains that it has not been demonstrated that retail competition can provide net benefits to all customers, rather than merely providing lower rates for a select few.

The Maryland People's Counsel also strongly opposes retail competition and urges the Commission to issue an affirmative declaration that retail wheeling is not in the interest of Maryland ratepayers at this time. Further, MPC opposes the Staff position that this issue be revisited in three to five years, because this will increase uncertainty.

MPC's primary concerns with retail competition revolve around the potential for cost-shifting, financial losses for shareholders, shortened planning horizons, and reliability problems.

Staff also does not believe retail competition is in the public interest at this time, but asserts that efforts should continue to increase customer choice. However, Staff acknowledges that many of the benefits of retail wheeling could be captured through wholesale competition coupled with rate design enhancements and other nonstructural changes.

Staff echoes the concerns of many commenters regarding the alleged adverse impacts of retail wheeling on reliability, the obligation to serve, stranded costs, the impact on the financial markets, and jurisdictional issues. Nonetheless, Staff suggests the Commission reevaluate retail wheeling in three to five years, in addition to monitoring and coordinating with other states on retail competition issues. Similarly, the Maryland Agencies also do not favor the adoption of retail competition at this time, but advocate further study.

All of the municipal and cooperative utility commenters oppose retail competition at this time. Southern Maryland Electric Cooperative, Inc. and Choptank Electric Cooperative, Inc. argue that the Commission should defer consideration of retail wheeling at least until a better working wholesale market is fully established and allowed to function. However, they do suggest that the Commission experiment with limited 'trial runs' of retail wheeling for select customers.

In addition to repeating concerns over reciprocity, stranded costs, and jurisdictional issues, SMECO and CEC urge the Commission to take into account the unique characteristics of rural electric cooperatives -- specifically, that retail competition may conflict with the goals of the Rural Electrification Act ('REA') [FN33] to maximize rural electrification and minimize rates by averaging costs among a large group of customers. Moreover, cooperative utilities are non-profit, and, therefore, have little ability to respond to competitive challenges.

Hagerstown and Williamsport also urge the Commission to reject retail wheeling until more is known about the transition taking place on the wholesale market and retail initiatives in other states. In addition, these two municipal utilities are particularly concerned with stranded costs and the 'cherry- picking' of their large commercial and industrial customers. However, they indicate that they might not object to retail wheeling if they maintained the exclusive right to distribution and could reduce their power purchases commensurately.

Berlin and Thurmont reiterate that the Commission should not overlook the unique characteristics of small municipal utilities. For example, Thurmont asserts that retail competition is inconsistent with the viability of small, non-profit full service public power systems. Moreover, the small municipal utilities generally believe that the greater resources of the IOU's provide them with an unfair competitive advantage.

The Pennsylvania Rural Electric Association, et al. argues that the benefits of retail competition do not outweigh its costs, as most of the economic benefits can be achieved for all with an increasingly competitive wholesale market. The PREA responds to the global competition argument for retail wheeling by pointing out that U.S. electricity rates are competitive compared to most industrialized nations.

In addition to concerns over planning, reliability, and stranded costs, the PREA claims ***285** that the states are federally preempted by the REA from compelling retail wheeling actions which would adversely affect the purpose of rural electric cooperatives to bring economically-priced electricity to rural areas. Further, the REA prohibits the disposal of a cooperative's property, rights, or franchises without the approval of the Rural Electrification Administration. [FN34]

SEED, along with most of the individual commenters, opposes retail competition because it encourages a short-term focus on price instead of costs to the detriment of the environment. Furthermore, it will jeopardize IRP, result in cost-shifting to residential consumers and others with no market power, as well as adversely impacting reliability.

The International Brotherhood of Electrical Workers fears that retail competition will result in job loss and create an unfair competitive edge for utilities outside of Maryland. They also argue that retail wheeling will only benefit large customers and that reliability will decline.

There are, however, several commenters that support retail competition. Delmarva asserts that if competition is good at the wholesale level, then it should also be good at the retail level. Delmarva also stresses, however, that it is not urging the Commission to act today; rather, it should plan for retail competition at some point in the future.

Likewise, DOE and EPA are not opposed in principle to retail competition, but believe it is necessary to move very carefully. DOE and EPA are particularly concerned with ensuring the achievement of important social objectives, such as environmental protection, in any move toward retail competition. Regarding jurisdiction over retail wheeling, DOE and EPA attached a legal brief to their comments which indicates that the states have authority to order retail wheeling, but the FERC would then have authority over the rates, terms, and conditions of retail transmission service.

The Mid-Atlantic Independent Power Producers also support efforts to enhance competition in retail markets; however, they believe that a competitive bulk power market should be a baseline. MAIPP also addresses fears of cost-shifting. MAIPP argues that cost-shifting will not occur because competition will make producers more efficient and cost inefficiencies will be squeezed out of the system.

The Industrial Users, along with the Westvaco Corporation ('Westvaco '), believe that competition is possible in Maryland today. The Industrial Users argue that only retail competition will ensure that a vibrant, competitive electric services industry will materialize with real benefits for all consumers. They further argue that the institutional, contractual and financial arrangements, and technical capabilities already exist to allow for retail competition. As such, the Industrial Users urge the Commission to introduce the concept of customer choice to the State's electric utility industry. The Industrial Users essentially agree with DOE and EPA that states have authority to order retail wheeling, while the FERC would then control most retail transmission service.

To support their views, the Industrial Users point to deregulation around the world and in other industries in the U.S. They also stress the need to be globally competitive.

Lastly, Enron Power Marketing, Inc. supports retail competition for all Maryland consumers, not just large users. However, EPMI strongly criticizes the poolco approach. EPMI maintains that delay will result in lost savings and accelerating prices which could result in the flight of industry from Maryland. EPMI also points to the deregulation of other industries to support their arguments.

2. Commission Findings

[14-17] The Commission has carefully considered the comments and testimony of the parties on the issue of retail competition. Based on the record in this proceeding, we have decided that retail wheeling is not in the public interest at this time.

The Commission acknowledges that there are potential benefits to retail competition. These benefits primarily revolve around allowing the free market to set the prices, terms, and conditions of electricity generation.

When a competitive market can be established, it can create strong incentives to cut costs, increase efficiency, and develop new ***286** products and services. It is, however, our view that the conditions needed to ensure a competitive retail market do not currently exist. Thus, an approach focusing on perfecting wholesale competition first is a more prudent policy at this time.

Maryland is not plagued with excessively high electricity prices. In fact, as previously indicated, Maryland's rates are quite competitive. This advantageous position obviates the need for dramatic changes. This is especially true when increased wholesale competition promises to bring further benefits to Maryland consumers.

The following discussion outlines the many problems and complexities associated with retail competition which were put forth and considered by the Commission in this proceeding. While extensive, this list is by no means exhaustive.

One major concern is reciprocity in neighboring states. As previously mentioned, no state has yet adopted full-scale retail wheeling. As such, Maryland would be alone in the region, indeed in the nation, if it adopted such a policy. Given such a situation, there is a real fear that other states' utilities could 'cherry-pick' or 'cream-skim' beneficial load in Maryland, leaving this State's utilities with the burden of less profitable customers. This would have many negative economic effects, not the least of which would be increases in costs to the remaining customers. This scenario is even more troublesome given that Maryland utilities would not have the opportunity to compete for load in their competitors' states. In short, retail wheeling without at least regional reciprocity is problematical at this time.

Also of concern is the issue of transition or stranded costs. Given a retail wheeling environment, if a retail customer purchased power from another source, native utility investment formerly used to service that customer might be stranded. Many believe that the regulatory compact entitles utilities to recover stranded costs that were prudently incurred to serve retail customers in their service territories. This is a highly controversial issue, and no clear consensus has emerged on how to deal with it. This issue merits continuing investigation.

We are concerned that costs unrecoverable in the competitive marketplace will be shifted to customers who are unable or unwilling to seek an alternate energy provider. These customers are commonly referred to as captive ratepayers. Under retail competition, there is some question as to whether costs will be 'squeezed' out of the system and not shifted to residential and smaller commercial customers.

We are also concerned about the potential impact of retail competition on system reliability. Current high levels of reliability depend largely on voluntary coordination between the region's utilities, particularly those in the PJM Interconnection and the APS companies. This coordination could be jeopardized if these same utilities were forced to compete for retail customers on the basis of price and service quality. Reliability also depends on long- range planning, which could be much more difficult in an industry highly focused on current market conditions.

We are also concerned that retail wheeling could jeopardize utility funding of environmental and social programs. If utilities are forced to compete, they will be unwilling (and perhaps unable) to shoulder the responsibility for these programs. As such, alternative funding would have to be found. Furthermore, it is possible that competition's emphasis on low prices will encourage, or even force, utilities to utilize cheap, but dirty, generation resources.

We also have unresolved questions about the impact of a retail competition regime on municipal and cooperative utilities. Many of these utilities believe retail wheeling will conflict with what they view as their mission -- namely, to lower electricity prices for their citizens and allow for local accountability. Among our unanswered concerns in this area is whether retail wheeling is consistent with the viability of small, non-profit public power systems. Another concern is whether retail wheeling runs counter to the goals and mandates of the REA.

Lastly, there are unresolved jurisdictional issues involved in ordering retail wheeling. The Commission is confident that its current authority over the electricity industry, as outlined in the Public Service Commission Law, [FN35] permits it to order retail wheeling. However, significant ***287** issues remain over the interface of this authority with federal regulation, and the complexities associated with regulating multijurisdictional utilities.

As stated previously, the Commission believes that the foregoing problems and complexities outweigh any potential benefits that may be achieved from retail wheeling at this time. This is not to say that the problems we have identified are insolvable. It is to say that prudence dictates a slower, more measured approach than that which would occur by ordering retail wheeling at this time. Furthermore, elsewhere in this order, we endorse competitive bidding as a means of tapping the benefits of a competitive wholesale market. As also noted above, the Commission believes that many of the benefits attributed to retail wheeling -- particularly decreased costs and increased efficiency at the generation level -- can be achieved through wholesale competition. Moreover, as explained later in this order, we continue to support the use of special contracts in limited situations, and are receptive to performance-based ratemaking proposals. These tools will further alleviate economic pressures for retail wheeling in the State.

As indicated earlier, we believe that wholesale competition, along with the other reforms indicated in this Order, should be permitted to work before retail wheeling is considered further. The wholesale market is still in its infancy and there are many unresolved issues on the federal level. Once these issues are addressed and the wholesale market is more robustly developed, it may become clear that additional reform is needed. To this end, the Commission will closely monitor policy development at the federal level, retail wheeling initiatives in other states, and the success of the changes embodied in this Order. The Commission will also endeavor to participate in all relevant federal proceedings and coordinate with other states on regional issues whenever appropriate. Based on this ongoing analysis, the Commission may in the future readdress the retail wheeling issue.

C. SPECIAL CONTRACTS AND RATE FLEXIBILITY

1. Position of the Parties

The majority of the commenters support the limited use of special contracts and rate flexibility. [FN36] The proponents include all of the Maryland investor-owned utilities. The IOU's argue that flexibility to offer prices, terms, and conditions that meet unique customer needs is necessary in order to quickly address competitive threats. These commenters also believe that cross- subsidies between rate classes should be eliminated, and that rates should be deaveraged. Moreover, they stress that special contracts should provide some contribution to fixed costs. Finally, they assert that special contracts may be used to attract, as well as retain, beneficial load.

The Maryland People's Counsel does not encourage the increased use of special contracts, but does recognize their value in limited applications. MPC stresses that if base rates reflect adequately the cost of service, customers should have to demonstrate extraordinary circumstances to justify rate adjustments.

Likewise, Staff believes that special contracts are a useful tool for addressing actual competitive conditions, and are superior to retail wheeling because they retain industry and minimize impacts on other customer classes. Staff also urges the Commission to consider rate deaveraging and further movement towards cost-based rates.

The Maryland Agencies as a group indicate their support for special contracts; the Department of Economic and Employment Development also advocates special incentive rates to attract industry to Maryland. Further, the Department of Defense and the Federal Executive Agencies ('DOD and FEA') [FN37] support special contracts and the elimination of cross-subsidies. DOD and FEA also indicate that they expect full access to any special rates which are offered other large customers.

The Industrial Users and Westvaco believe that special contracts are useful in the interim before the adoption of full retail competition. These industrial commenters also advocate deaveraging so that rates produce a closer match between cost causation and cost responsibility.

Furthermore, both SMECO and CEC and ***288** Hagerstown and Williamsport support special contracts and greater flexibility to meet competitive challenges.

On the other hand, several commenters oppose special contracts and rate flexibility. EPMI argues that flexibility to discriminate in pricing is not a substitute for competition, and as such, urges the Commission to reject any such initiatives.

The Mid-Atlantic Independent Power Producers echo EPMI's argument that flexible pricing is not a substitute for competition. MAIPP explains that special prices do not address the underlying problem of economically inefficient electricity rates to the remaining customers, and, therefore, are a superficially attractive approach to helping utilities meet the competition. Moreover, MAIPP argues that such policies are anticompetitive and will inhibit progress towards a truly competitive marketplace. MAIPP asserts that utilities should only be permitted to charge flexible rates when comprehensive restructuring is introduced.

SEED contends that utilities should not give industrial customers 'bribes' to remain on their systems; rather, they should help industrial customers reduce their use of electricity. Mr. David Lapp also asserts that flexible pricing for only some customers is not competition and is discriminatory.

2. Commission Findings

[18-22] After careful review of the record in this proceeding, the Commission agrees that utilities need the flexibility to offer prices, terms, and conditions that meet unique customer needs, in order to respond to competitive challenges. As such, we recognize the need to entertain requests for special rates and pricing flexibility. Further, in response to those advocating deaveraging and the elimination of cross-subsidies, the Commission will continue its ongoing policy of moving rates for all customer classes towards cost.

In order to ensure the judicious use of **special contracts** and rate flexibility, the Commission will establish guidelines to ensure that they are used only in circumstances that result in net benefits for all utility customers. First, any special rate should recover customer-specific **variable costs** and some contribution to fixed costs. Without this requirement, the utility might be put in the anomalous position of supplying a customer at a loss. Thus, remaining customers would actually be worse off by retention of the customer. This would nullify one of the most important rationales for **special contracts**. That is, that even though a special rate for one customer may ultimately raise rates for those without competitive options, those customers are still better off than if the special rate customer left the system altogether.

Second, the utility seeking approval of a special contract must demonstrate that the special rate customer in fact does have viable competitive alternatives. These alternatives may include the opportunity to exploit a market-based price offered the customer, or the ability to self-generate or relocate.

Third, while the Commission understands that special contracts may result in cost-shifting, it will not permit excessive rate increases for other customers. Accordingly, it may be appropriate in some instances for shareholders to bear some of the burden for these special contracts.

The Commission has also taken note of the practice of some state commissions of requiring energy audits prior to approving special contracts. These audits often reveal opportunities to reduce electricity consumption such that a special contract is no longer needed. The Commission believes this practice has merit, and suggests that utilities consider this option before proposing special contracts.

Lastly, the Commission will consider proposals to develop cost-based economic development rate plans. It should be recognized that the Commission has addressed this issue in the past. [FN38]

D. PERFORMANCE-BASED RATEMAKING

1. Position of the Parties

Most of the parties in this proceeding that address the issue generally support performance-based ratemaking and other incentive mechanisms to encourage utilities to cut costs and increase efficiency. Many of these ***289** commenters argue that the current 'cost-plus' system is inefficient because it virtually guarantees that utility costs will be recovered.

The various commenters propose several different types of PBR schemes. Four of the most common are: benchmarking; fuel rate incentives; price caps; and profit-sharing. The commenters essentially define benchmarking as requiring utilities to reach efficiency and performance targets as a condition of full cost recovery. These targets are based on comparisons to a group of similarly- situated utilities. Fuel rate incentives, as discussed by the parties, often involve reforming the fuel adjustment clause so that fuel costs are not automatically recovered by utilities. They also include assessing penalties or rewards based on the efficiency of fuel procurement.

With price caps, rates are capped at a certain price (usually after a rate case). The utility then has the flexibility to set prices at any level below the cap. Many price cap plans allow annual adjustments to reflect changes in inflation and productivity rates.

Lastly, profit-sharing, as envisioned by the parties, refers to a system whereby savings resulting from utility cost-cutting and efficiency are shared between customers and shareholders. Often, losses above a certain level are also shared.

While most of the commenters support some form of performance-based ratemaking, there is no consensus on what type of PBR is best. Indeed, many commenters support some types of PBR, but oppose others. PEPCO is one of the few commenters that expresses support for all four types of PBR discussed above. Moreover, PEPCO's proposal for its own corporate restructuring envisions a performance-based, contract-like arrangement between the T&D Division and the G Division.

Delmarva supports PBR in principle, but believes that increasing generation competition will bring more benefits. As such, Delmarva contends that PBR is most appropriate for T&D and other remaining monopoly services.

Likewise, PE supports PBR as a means of introducing competition in a controlled manner without imposing significant risks. To this end, PE urges the Commission to establish a work group to study and adopt standards for incentive-based ratemaking.

BGE simply asserts that PBR can complement competitive segments of the business.

The Maryland People's Counsel generally favors incentives, particularly in terms of reducing fuel costs. However, it does not advocate deaveraging the fuel rate or the recovery of fuel costs through base rates. MPC does recommend profit-sharing, so long as there are safeguards against manipulation. In addition, MPC suggests using incentive programs for employees. On the other hand, MPC opposes price caps and believes that benchmarks are often set too low. However, MPC does support using some comparative information to assess a utility's performance.

Staff supports PBR, but emphasizes that any PBR plans must provide benefits for both ratepayers and shareholders. The Maryland Agencies also support PBR and recommend that the Commission delegate the issue to a work group to fully develop an implementable plan.

DOE and EPA believe that PBR offers significant potential to promote economic efficiency. However, they underscore that any PBR scheme should consider energy efficiency, environmental quality, and fuel diversity. Moreover, the two federal agencies suggest the Commission consider revenue caps because, unlike price caps, there is no incentive to increase sales under a revenue cap. DOD and FEA also note their support for incentive mechanisms, especially fuel incentives and price caps.

The Industrial Users believe that where natural monopolies exist, certain incentive mechanisms may be used to promote greater efficiency. However, the Industrial Users strongly oppose incentive regulation for services subjected to market forces.

Similarly, EPMI and MAIPP support PBR for monopoly services. For competitive services, they believe the Commission should look beyond simply replacing or reforming existing regulation and allow market mechanisms to operate fully.

The PREA notes its support for PBR. SEED believes the Commission should give utilities incentives to cut costs, but that these ***290** incentives should include environmental performance factors. Further, SEED favors eliminating the dollar-for-dollar recovery of fuel costs, as this would provide an incentive for renewables many of which have no fuel costs.

Lastly, the only commenters that oppose PBR altogether are Hagerstown and Williamsport. They contend that incentives are inappropriate for municipal utilities because municipals are non-profit and have no shareholders.

2. Commission Findings

[23-25] The Commission is of the opinion that there are significant benefits to performance-based ratemaking, namely the provision of incentives for utilities to cut costs and increase efficiency. PBR may also be a means of introducing limited competition without imposing significant risk. Other potential benefits include: improved utility ability to react to competitive forces; the furnishing of stronger incentives to innovate, utilize cost- effective inputs, and accelerate technological adoption; the easing of administrative and regulatory burdens; and the enhancement of price stability and predictability.

The Commission believes, however, that PBR is only appropriate for monopoly services. Where competition exists, PBR mechanisms are unnecessary because the rigors of the marketplace are generally sufficient to enforce efficiency. As such, current candidates for PBR proposals will likely include T&D services and existing generation. On the other hand, new generation, as discussed earlier in this order, will be subject to competitive bidding. With a bidding scheme, the ability to recover costs and make a profit at the bid price is enough of an incentive to ensure maximum productivity.

This is not to say that the Commission believes that the current regulatory system is ineffective in encouraging utilities to be efficient. In fact, in recent years this State's electric utilities have made significant strides in cutting costs and improving productivity largely without the added incentives provided by PBR. The Commission expects these improvements to continue, and will carefully scrutinize the necessity for any PBR plan.

The Commission is willing to consider PBR proposals on a utility-specific basis. In accordance with Staff's recommendations, an appropriate proposal must offer benefits for both ratepayers and shareholders. The Commission encourages utilities to meet with Commission Staff and other stakeholders to discuss their proposals before filing them with the Commission. Lastly, the Commission is aware that some PBR mechanisms, such as price caps, may require changes to the Commission's enabling legislation.

E. IRP, DSM, RENEWABLES, AND SOCIAL PROGRAMS

1. Position of the Parties

It is believed by many that increasing competition and the resulting restructuring of the electricity industry will, or should, affect the current regulatory treatment of IRP, DSM, renewables, and social programs. In this proceeding, the commenters were asked to address these issues.

All of the State's investor-owned utilities believe that the burdens of environmental and social programs should be applied to all competitors, eliminated altogether, or supplied by the State. The IOU's contend that utility responsibility for these programs puts them at a competitive disadvantage vis- a-vis alternate power suppliers, such as independent power producers. Delmarva and PE assert that such goals and programs are more appropriate for legislative, rather than regulatory, action.

Regarding IRP, both Delmarva and PE argue that an increasingly competitive electricity industry is incompatible with the present system of IRP -- primarily because of its focus on the long-term. BGE, however, points out that while IRP is not suitable in a retail wheeling environment, it would serve an important role in procuring power in a system with greater wholesale competition. Nonetheless, BGE goes on to assert that IRP decisions need to be refocused on the short-term, as this more accurately reflects the unpredictable conditions facing a utility in a more dynamic marketplace.

Moreover, the State's IOU's support ***291** subjecting DSM programs to competition. Essentially, they believe that DSM should be required to withstand a market test by competing without subsidies. PE advocates subjecting DSM resources to bidding, and BGE suggests that utilities be permitted to market DSM as a service. Among the IOU's there was little or no support for decoupling as a way of eliminating the utilities' disincentive to promote DSM. [FN39]

The IOU's generally support the further development and implementation of renewable technologies, but only if they are cost-effective. All indicate that they are researching renewable opportunities, but that currently there are few economic alternatives available.

MPC urges the Commission to reaffirm its commitment to long-range IRP. MPC contends that IRP is, in part, responsible for the State's electricity rates being below average. MPC also supports the continuation of DSM programs. Further, MPC is a proponent of renewable energy and believes that some incentives in this area may be appropriate. However, MPC states that it has not adopted an official policy on set-asides or preferences.

Staff also believes that long-range IRP and conservation are in the public interest, and urges the Commission to make a general policy statement to this effect. In addition, Staff supports DSM, but advocates testing these programs against the lowest cost supply increment.

Likewise, the Maryland Agencies believe that commitment to long-range IRP and energy efficiency continue to be in the public interest. The Maryland Agencies suggest rewarding attempts by utilities to minimize environmental impacts.

DOE and EPA maintain that increased competition should not be pursued independent of equally important state and national energy and environmental policy objectives. These agencies stress, however, that utilities should not be put at a disadvantage relative to other electricity suppliers. Specifically, they contend that restructuring should: recognize the value of fuel and energy technology diversity, provide incentives for investment in new energy technologies, support IRP, and promote DSM investment. DOE and EPA also note that decoupling can be an effective means of removing disincentives for energy efficiency and DSM measures.

DOD and FEA simply assert that environmental concerns and energy conservation issues must be addressed in the transition to a more competitive electricity industry.

The Industrial Users argue that the need for IRP should diminish with increased competition, because the market will decide the least-cost mix more efficiently. Furthermore, the Industrial Users maintain that cost-effective DSM will flourish in a more competitive environment. They oppose decoupling, however, as this neutralizes utility incentives to be efficient, accept business risk, and provide services at competitive rates.

The Industrial Users advocate requiring renewables to compete on their own merits. They also argue that a more efficient industry can better afford environmental safeguards. Moreover, they assert that low income people will benefit more from low electricity rates than from subsidies.

MAIPP contends that federal, state, and local laws are sufficient to protect the environment. They also advocate eliminating DSM subsidies and requiring DSM to compete with the retail cost of electricity. Lastly, they recommend the creation of an assistance program funded by a universal access charge to help needy customers.

SMECO and CEC also believe that DSM should compete with supply options. In addition, they question the cost-effectiveness of renewable technologies.

The towns of Hagerstown and Williamsport urge the Commission to thoroughly review social costs and opportunities when it considers changes.

SEED strongly advocates the internalization of environmental costs. To this end, they contend the integrated resource planning process should be structured to more fully account for environmental costs and the benefits of renewables and conservation. Like many other commenters, SEED believes DSM and supply-side resources should compete with each other.

Further, SEED favors set-asides and preferences for renewables. They stress that ***292** renewables have no fuel costs, and in many cases zero pollutant emissions. In any event, SEED asserts that some renewables are already competitive over the long-term, and others are on the brink of commercialization.

The Maryland Safe Energy Coalition ('MSEC') [FN40] endorses SEED's testimony, and stresses its belief in regulatory support for energy efficiency and conservation. MSEC also urges stronger incentives for least-cost planning and DSM.

The Center for Energy and Economic Development ('CEED') [FN41] strongly opposes the internalization of environmental and societal costs. CEED contends that the costs of complying with the environmental laws are already internalized. CEED goes on to point out that coal plants are significantly cleaner today than in the past, and are much more cost-effective than renewables.

The individual commenters generally fear that competition could have a negative effect on the environment, energy efficiency, conservation, the development of renewables, and programs for low income people. Mr. David Lapp offers some specific suggestions. He encourages the Commission to remove barriers to competition in energy efficiency technologies (e.g., utility control of billing and metering information) and institute competitive bidding for DSM.

2. Commission Findings

[26, 27] The Commission's goal is to preserve the benefits of IRP, DSM, renewables, and social programs within the context of a more competitive environment, while at the same time not disadvantaging the State's electric utilities in competitive markets.

Specifically, the Commission reaffirms its commitment to IRP. We believe IRP is in the public interest, and has continued importance even given the changes outlined elsewhere in this Order. IRP has resulted in significant benefits in Maryland, including lower costs, greater efficiencies, and reductions in demand for capacity and energy (with attendant reductions in pollutant emissions). We recognize, however, that the IRP process will have to evolve along with the rest of the industry.

The Commission agrees that current notions of IRP may be incompatible with full retail competition. As such, we anticipate the need for additional changes to the IRP process should retail wheeling become a reality. However, this is not a current issue in Maryland because retail wheeling will not be instituted at this time.

Rather, we endorse competitive bidding as a means of taking advantage of generation and other resources available on the competitive wholesale market. In a wholesale competition environment, IRP can play an important role in a utility's procurement function.

Furthermore, we have previously indicated that environmental factors, inter alia, must be considered in any competitive bid.

The Commission continues to also believe that DSM offers important benefits to ratepayers and the industry. The reduction in the demand for electricity achieved by these programs has resulted in the need for less capacity. This, in turn, has significant collateral benefits in terms of reducing pollution and other negative environmental impacts.

The Commission is aware of complaints that DSM programs are not cost- effective. We also are aware of arguments that utilities have a conflict of interest in administering DSM, which often detracts from the success of these programs.

As previously mentioned, the Commission will allow DSM resources to bid against supply-side proposals pursuant to its competitive bidding policy for all new capacity. This will ensure that cost-effective DSM is given full and fair consideration. If DSM is more cost-effective, and meets the other necessary requirements, it will win the solicitation.

However, DSM's consideration in future competitive bidding does not address reducing the immediate consumption of electricity. As such, the Commission continues to support existing DSM programs. We emphasize that such programs are administered at the retail level, and, therefore, will not hinder Maryland utilities in competing in the wholesale power market. The Commission reiterates that DSM must also be cost-effective.

***293** While the Commission is aware that the energy services industry has grown considerably in the past several years, we continue to believe that appropriate incentives to encourage ratepayer participation in DSM programs are necessary. While several energy service companies market conservation and energy efficiency services to Maryland ratepayers, the availability and affordability of these services to the average consumer is unclear. We direct our Staff to investigate this matter, and report its findings to us. On the other hand, most larger customers already have the sophistication and the means to take advantage of these opportunities, and many in fact do so. The Commission will carefully monitor the development of the energy services industry, and this may cause it to revise its view of the need for DSM incentives.

In the meantime, we encourage utilities to develop innovative ways of increasing efficient and cost-effective consumer participation in DSM. One proposal we find interesting involves providing financing for energy-efficiency and conservation measures, as opposed to direct rebates.

The Commission has already provided its views on renewables in its discussion on competitive bidding. In short, we support the continued development of renewable technologies, but will not force this State's utilities to purchase or implement uneconomic resources, renewable or otherwise. As such, we will not approve any preferences or set-asides favoring renewable technologies. We also decline to engage in any process of internalizing environmental costs over and above those internalized as a result of environmental laws. However, the Commission strongly supports the utilization of cost-effective renewable resources. All of the State's IOU's, and several other utilities, indicate that they are actively researching and experimenting with renewable technologies. The Commission encourages them to continue this development.

Many of the commenters, particularly the IOU's, express concerns over utility responsibility for other social and environmental programs. The concern is that utility responsibility for these matters inhibits their ability to provide inexpensive electricity services, and thereby to compete with alternate suppliers (or self-generation) in a more competitive electricity industry. To remedy this, the IOU's recommend that any such burdens either be applied to all competitors, eliminated altogether, or provided by the State through its powers of general taxation.

The Commission does not believe that the reforms outlined in this Order will affect the current treatment of social and environmental programs. This Order primarily contemplates fostering wholesale competition through competitive bidding for future power supplies. The costs for social and environmental programs, however, are allocated to retail ratepayers. Since the Commission is not instituting retail wheeling, we envision the continuation of the aforementioned programs in their current form. We reemphasize that this will not inhibit a Maryland utility's ability to compete in any bid for power, including its own.

Finally, we will make every effort to ensure that the State's utilities are not unduly or unfairly burdened with regulatory obligations which could hinder the move to a future industry paradigm (such as retail competition). As such, any new programs to be funded through utility rates will receive added scrutiny.

III. CONCLUSION

This nation's electricity industry is changing. The current system of regulated monopolies which has provided the country with the most reliable and extensive electricity system in the world, is being challenged by competition. Many issues surrounding this monumental transformation are unresolved. What is clear, however, is that change is here, and it promises important benefits and opportunities, as well as posing future uncertainties.

Maryland currently enjoys an enviable position; it is blessed with a comparatively efficient, reliable electricity industry that provides the State with relatively low cost power. The benefits this provides to Maryland are innumerable. The challenge to the Commission, therefore, is to provide the electricity industry with the competitive tools to maintain and enhance this position that is advantageous to all ***294** stakeholders.

Given the current stage of restructuring in the industry, the Commission believes that the reforms embodied in this Order provide the State's utilities with these necessary tools. We have also provided adequate protections for ratepayers. The Commission emphasizes that this is a continuous process, and as such, the Commission's guidance will evolve along with the development of the industry.

IT IS, THEREFORE, this 18th day of August, in the year Nineteen Hundred and Ninety-five, by the Public Service Commission of Maryland,

ORDERED: (1) That the policies set forth herein are adopted.

(2) That this matter is hereby closed on the docket of the Commission.

FOOTNOTES

FN1 Pub. L. No. 95-617, 92 Stat. 3117.

FN2 15 U.S.C. § § 79 et seq.

FN3 Pub. L. No. 102-486, 106 Stat. 2776.

FN4 16 U.S.C. § 824j.

FN5 Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 70 F.E.R.C. 61,357, Docket Nos. RM95-8-000 and RM94-7-001, issued March 29, 1995 ('Open Access NOPR' or 'NOPR').

FN6 See id. slip op. at 48 (citing Stranded Cost NOPR at 32,866; American Electric Power Service Corporation, 67 F.E.R.C. 61,168, clarified, 67 F.E.R.C. 61,317 (1994)).

FN7 The FERC first stated this principle in American Electric Power Service Corporation, 67 F.E.R.C. 61,168, 61,490, Docket No. ER93-540-001, issued May 11, 1994 ('an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's use of the system.')

FN8 Generally, the term stranded costs refers to costs prudently incurred by utilities that are rendered uneconomic in a more competitive marketplace.

FN9 Connecticut DPUC Investigation into Retail Electric Transmission Service, Docket No. 93-09-29, issued September 9, 1994.

FN10 PJM refers to the Pennsylvania-New Jersey-Maryland Interconnection, a voluntary, highly coordinated power pool that serves electricity consumers in Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, and Virginia.

FN11 See Staff Discussion Paper, New Directions in Electric Regulation at 4 and Appendix A.

FN12 See Energy Prices and Taxes (Second Quarter 1994), published by the International Energy Agency of the Organization for Economic Cooperation and Development (OECD) at 314-315.

FN13 MAAC is the acronym for the Mid-Atlantic Area Council, which is a regional reliability council.

FN14 The Maryland Agencies include the Departments of Agriculture, Economic and Employment Development, Environment, Natural Resources, Transportation, the Maryland Energy Administration, and the Maryland Office of Planning. The agencies were represented in this proceeding by the Maryland Office of the Attorney General.

FN15 DOE and EPA state that they represent the energy policy perspective of the Clinton Administration.

FN16 A poolco can take many forms, however, it basically consists of an independent system operator which controls the dispatch of power over the transmission lines.

FN17 The PREA submitted comments jointly with the Allegheny Electric Cooperative, Inc. on behalf of Somerset Rural Electric Cooperative, Inc.

FN18 The Maryland SEED Campaign is an environmental advocacy group, representing over 2,500 Maryland citizens who are concerned about energy use and production in the State.

FN19 See Initial Comments of the Potomac Edison Company, Appendix No. 1 'Electric Power Competition: A Proposal for Maryland', prepared by Putnam, Hayes, & Bartlett, Inc. (This proposal advocates the establishment of an independent entity called a poolco, which would coordinate system operations, manage spot energy trading, and price ancillary services and system interactions in real time.)

FN20 The Industrial Users include Bethlehem Steel Corporation, General Motors Corporation, the Maryland Industrial Group, and the Electricity Consumers Resource

Council.

FN21 See, e.g., Re Baltimore Gas and Electric Company, Case No. 8241, Phase II (1992) (Perryman bid) and Re Delmarva Power and Light Company, Case Nos. 8201, 8052 (1991) (Challenge 2000 bid).

FN22 See supra note 7.

FN23 See Order Providing Guidance Concerning Pending and Future Proceedings Involving Non-Discriminatory Open Access Transmission Services, Docket Nos. ER93-540-000, et al. issued March 29, 1995 and clarified June 29, 1995.

FN24 APS is the parent corporation for three utilities -- Monongahela Power Company, Potomac Edison Company, and West Penn Power Company -- whose generation and T&D facilities are interconnected and operated as a single integrated electric utility system. The Potomac Edison Company serves electricity customers in Western Maryland.

FN25 Docket No. RM94-20-000 issued October 26, 1994.

FN26 See Comments of the Members of the Pennsylvania-New Jersey-Maryland Interconnection in Docket No. RM94-20-000.

FN27 Open Access NOPR, slip op. at 290-291.

FN28 Docket Nos. TX94-8-000 and TX94-10-000, respectively.

FN29 See Md. Ann. Code art. 78, § § 28(g) and 56.

FN30 See Md. Ann. Code art. 78, § 28(c&g).

FN31 See cases cited supra note 21.

FN32 Retail competition (also known as retail wheeling or direct access) refers to permitting retail electricity customers to purchase generation from a supplier other than their native utility, and having that power wheeled to them over the native utility's lines. Transmission and distribution services, as natural monopolies, would continue to be subject to comprehensive regulation.

FN33 7 U.S.C. § § 900 et seq.

FN34 The Rural Electrification Administration has recently been renamed the Rural Utilities Service.

FN35 Md. Ann. Code art. 78, § 1 et seq.

FN36 Special contracts and rate flexibility primarily refer to special rates which are given to industrial and other large customers to prevent them from self-generating or relocating. Maryland electric utilities currently have a few special contracts for large customers. Two types of special contracts are those in which a rate is developed based on a specific customer's cost to the system (i.e., a deaveraged rate) or a rate designed to meet market prices available to the customer. In addition, special contracts and rate flexibility refer to economic development rates, market niche rates, and special rate proceedings.

FN37 DOD and FEA represent the interests of the federal agencies as energy consumers.

FN38 See Re Conowingo Power Company, Case No. 8011, Order No. 67786, 78 Md. PSC 228 (1987) (In a split decision, the Commission approved, as modified, an application by an electric utility for authority to implement an economic development tariff aimed at certain industrial customers.)

FN39 Currently, utilities receive revenue for each unit of electricity they sell. As such, many argue that utilities have a disincentive to effectively implement DSM programs to reduce the demand for electricity. Decoupling refers to breaking this link between a utility's sales of electricity and the revenues it receives. Basically, if decoupling were instituted, a utility would recover the same amount of revenue regardless of how many units of electricity it sold. Therefore, the current incentive to increase electricity consumption (and disincentive for DSM) would be eliminated.

FN40 MSEC is an environmental consumer organization.

FN41 CEED is a non-profit association which primarily represents the interests of the coal and railroad industries.

***295** EDITOR'S APPENDIX

Citations in Text

[CONN.] Re Investigation into Retail Electric Transmission Service, 155 PUR4th 209, Docket No. 93-09-29, Sept. 9, 1994.
[MD.] Re Electric Services, Market Competition, and Regulatory Policies, Case No. 8678, Order No. 71459, 85 Md PSC 130, Sept. 19, 1994.
[MICH.] Re Association of Businesses Advocating Tariff Equity, 150 PUR4th 409, Case No. U-10143, Apr. 11, 1994.

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